

ANNEX 2 Methodology and Data for Estimating CO₂ Emissions from Fossil Fuel Combustion

2.1. Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion

Carbon dioxide (CO₂) emissions from fossil fuel combustion were estimated using a “bottom-up” methodology characterized by six steps. These steps are described below.

Step 1: Determine Energy Consumption by Fuel Type and Sector

The bottom-up methodology used by the United States for estimating CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the Intergovernmental Panel on Climate Change (IPCC) for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). Basic consumption data are presented in Columns 2 through 8 of Table 2-1 through Table 2-13, with totals by fuel type in Column 8 and totals by end-use sector in the last rows. Fuel consumption data for the bottom-up approach were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy. These data were first gathered in physical units, and then converted to their energy equivalents (see “Energy Conversions” in Annex 6.5). The EIA data were collected through a variety of consumption surveys at the point of delivery or use and qualified with survey data on fuel production, imports, exports, and stock changes. Individual data elements were supplied by a variety of sources within EIA. Most information was taken from published reports, although some data were drawn from unpublished energy studies and databases maintained by EIA.

Energy consumption data were aggregated by sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories), primary fuel type (e.g., coal, natural gas, and petroleum), and secondary fuel type (e.g., motor gasoline, distillate fuel, etc.). The 2002 total energy consumption across all sectors, including territories, and energy types was 82,994.1 trillion British thermal units (TBtu), as indicated in the last entry of Column 8 in Table 2-1. This total includes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which are deducted in later steps.

Electricity consumption information was allocated to each sector based on EIA’s distribution of electricity retail sales to ultimate customers (i.e., residential, commercial, industrial, and other). Because the “other” fuel use includes sales to both the commercial and transportation sectors, EIA’s limited transportation electricity use data were subtracted from “other” electricity use and also reported separately. This total was consequently combined with the commercial electricity data. Further information on these electricity end uses is described in EIA’s *Monthly Energy Review* (2003a).

There were a number of modifications made in this report that may cause consumption information herein to differ from figures given in the cited literature. These are 1) the reallocation of some coking coal, petroleum coke, and natural gas consumption for ammonia production to the Industrial Processes chapter, 2) corrections for synthetic natural gas production, 3) corrections for ethanol added to motor gasoline, and 4) corrections for biogas in natural gas.

First, portions of the fuel consumption data for three fuel categories—coking coal, petroleum coke, and natural gas—were reallocated to the Industrial Processes chapter, as these portions were actually consumed as raw material during non-energy related industrial processes. Coking coal, also called “coal coke,” is used as a raw material (specifically as a reducing agent) in the blast furnace process to produce iron and steel, and therefore is not used as a fuel for this process. Similarly, petroleum coke is used in multiple processes as a raw material, and is thus not used as a fuel in those applications. The processes in which petroleum coke is used include 1) ferroalloy production, 2) aluminum production (for the production of carbon anodes and cathodes), and 3) titanium dioxide production (in the chloride process). Finally, natural gas consumption is used for the production of ammonia.

Consumption of these fuels for non-energy purposes is presented in the Industrial Processes chapter, and is removed from the energy and non-energy consumption estimates within the Energy chapter.

Second, a portion of industrial coal accounted for in EIA combustion figures is actually used to make “synthetic natural gas” via coal gasification. The energy in this gas enters the natural gas stream, and is accounted for in natural gas consumption statistics. Because this energy is already accounted for as natural gas, it is deducted from industrial coal consumption to avoid double counting. This makes the figure for other industrial coal consumption in this report slightly lower than most EIA sources.

Third, ethanol has been added to the motor gasoline stream for several years, but prior to 1993 this addition was not captured in EIA motor gasoline statistics. Starting in 1993, ethanol was included in gasoline statistics. However, because ethanol is a biofuel, which is assumed to result in no net CO₂ emissions, the amount of ethanol added is subtracted from total gasoline consumption. Thus, motor gasoline consumption statistics given in this report may be slightly lower than in EIA sources.

Fourth, EIA natural gas consumption statistics include “biomass gas,” which is upgraded landfill methane that is sold to pipelines. However, because this gas is biogenic, the biomass gas total is deducted from natural gas consumption. The subtraction is done only from natural gas in the industrial sector, as opposed to all end-sectors, because the biogas amount is small. Due to this adjustment—and the ammonia adjustment mentioned previously—industrial natural gas consumption in this report is slightly lower than in EIA sources.

There are also three basic differences between the consumption figures presented in Table 2-1 through Table 2-13 and those recommended in the IPCC emission inventory methodology.

First, consumption data in the U.S. inventory are presented using higher heating values (HHV)¹ rather than the lower heating values (LHV)² reflected in the IPCC emission inventory methodology. This convention is followed because data obtained from EIA are based on HHV. Of note, however, is that EIA renewable energy statistics are often published using LHV. The difference between the two conventions relates to the treatment of the heat energy that is consumed in the process of evaporating the water contained in the fuel. The simplified convention used by the International Energy Agency for converting from HHV to LHV is to multiply the energy content by 0.95 for petroleum and coal and by 0.9 for natural gas.

Second, while EIA’s energy use data for the United States includes only the 50 U.S. states and the District of Columbia, the data reported to the Framework Convention on Climate Change are to include energy consumption within territories. Therefore, consumption estimates for U.S. territories were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table 2-1 through Table 2-13. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, the domestic sectoral consumption data in Table 2-1 through Table 2-13 include bunker fuels used for international transport activities and non-energy uses of fossil fuels. The IPCC requires countries to estimate emissions from international bunker fuels separately and exclude these emissions from national totals, so international bunker fuel emissions have been estimated in Table 2-14 and deducted from national estimates (see Step 5). Similarly, fossil fuels used to produce non-energy products that store carbon rather than release it to the atmosphere are provided in Table 2-15 and deducted from national emission estimates (see Step 3). The final fate of these fossil fuel based products is dealt with under the waste combustion source category in cases where the products are combusted through waste management practices.

Step 2: Determine the Carbon Content of All Fuels

The carbon content of combusted fossil fuels was estimated by multiplying energy consumption (Columns 2 through 8 of Table 2-1 through Table 2-13) by fuel-specific carbon content coefficients (see Table 2-16 and Table 2-17) that reflect the amount of carbon per unit of energy in each fuel. The resulting carbon contents are sometimes referred to as potential emissions, or the maximum amount of carbon that could potentially be released to the atmosphere if all carbon in the fuels were oxidized. The carbon content coefficients used in the U.S. inventory were

¹ Also referred to as Gross Calorific Values (GCV).

² Also referred to as Net Calorific Values (NCV).

derived by EIA from detailed fuel information and are similar to the carbon content coefficients contained in the IPCC's default methodology (IPCC/UNEP/OECD/IEA 1997), with modifications reflecting fuel qualities specific to the United States.

Step 3: Adjust for the amount of Carbon Stored in Products

Depending on the end-use, non-energy uses of fossil fuels can result in long term storage of some or all of the carbon contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store carbon, but can lose or emit some of this carbon when they are used and/or burned as waste.³

The amount of carbon in non-energy fossil fuel products was based upon data that addressed the fraction of carbon that remains in products after they are manufactured, with all non-energy use attributed to the industrial, transportation, and territories end-use sectors. This non-energy consumption is presented in Table 2-15. These data were then multiplied by fuel-specific carbon content coefficients (Table 2-16 and Table 2-17) to obtain the carbon content of the fuel, or the maximum amount of carbon that could remain in non-energy products (Column 5 Table 2-15). This carbon content was then multiplied by the fraction of carbon assumed to actually have remained in products (Column 6 of Table 2-15), resulting in the final estimates by sector and fuel type, which are presented in Columns 7 and 8 of Table 2-15. A detailed discussion of carbon stored in products is provided in the Energy chapter and in Annex 2.3.

Step 4: Subtract the Amount of Carbon Exported as CO₂.

The value for potential carbon emissions from industrial “other” coal has been adjusted to account for CO₂ exports to Canada from 2000 through 2002. This CO₂ was generated as a byproduct from the production of synthetic natural gas from coal gasification by the Dakota Gasification Plant in North Dakota. Since October 2000, approximately 34 Bcf per year (about 1.9 Tg) of this byproduct CO₂ has been exported by pipeline to Saskatchewan, Canada, to be used in enhanced oil recovery applications. Since this CO₂ is not emitted to the atmosphere in the United States, it is subtracted from the potential carbon emissions from industrial other coal. As the CO₂ exports did not commence until October 2000, one-fourth of the value for annual CO₂ exports was subtracted from the potential carbon emissions from industrial other coal in 2000. The entire value for annual CO₂ exports (1.9 Tg) was subtracted for 2001 and 2002. For the remainder of the time series (i.e., from 1990-1999) the CO₂ emitted from the Dakota Gasification Plant is treated as emissions from fuel combustion.⁴

Step 5: Subtract Carbon in International Bunker Fuels

Emissions from international transport activities, or international bunker fuel consumption, are not included in national totals, as required by the IPCC (IPCC/UNEP/OECD/IEA 1997). There is currently disagreement internationally as to how these emissions should be allocated, and until this issue is resolved, countries are asked to report them separately. EIA energy statistics, however, include these bunker fuels—jet fuel for aircraft, and distillate fuel oil and residual fuel oil for marine shipping—as part of fuel consumption by the transportation end-use sector. To compensate for this inclusion, international bunker fuel emissions⁵ were calculated separately (see Table 2-14) and the carbon content of these fuels was subtracted from the transportation end-use sector. International bunker fuel emissions from military activities were developed using data provided by the Department of Defense as described in the International Bunker Fuels section of the Energy chapter and in Annex 3.7. The calculations of

³ See Waste Combustion section of the Energy chapter and Annex 3.6 for a discussion of emissions from the combustion of plastics in the municipal solid waste stream.

⁴ Although these emissions are not actually due to combustion, but to process venting, they are accounted for under CO₂ from fossil fuel combustion. Additionally, the venting of CO₂ from the Dakota Gasification Plant is not reported to the EIA with the “vented and flared” CO₂ data because the data reported to EIA are for operation of natural gas flares, not for process vent emissions.

⁵ Refer to the International Bunker Fuels section of the Energy chapter for a description of the methodology for distinguishing between bunker and non-bunker fuel consumption.

international bunker fuel emissions followed the same procedures used for other fuel emissions (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).

Step 6: Account for Carbon that Does Not Oxidize During Combustion

Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted in a gaseous form to the atmosphere. Rather, it remains behind as soot, particulate matter and ash. The estimated fraction of carbon not oxidized in U.S. energy conversion processes due to inefficiencies during combustion ranges from 0.5 percent for natural gas to 1 percent for petroleum and coal. Except for coal these assumptions are consistent with the default values recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997). In the United States, unoxidized carbon from coal combustion was estimated to be no more than one percent (Bechtel 1993). Table 2-16 presents fractions oxidized by fuel type, which are multiplied by the net carbon content of the combusted energy to give final emissions estimates.

Of the fraction of carbon that is oxidized (e.g., 99 to 99.5 percent), the vast majority is emitted in its fully oxidized form as carbon dioxide (CO₂). A much smaller portion of this “oxidized” carbon is also emitted as carbon monoxide (CO), methane (CH₄), and non-methane volatile organic compounds (NMVOCs). When in the atmosphere, though, these partially oxidized or unoxidized carbon compounds are generally oxidized to CO₂ through atmospheric processes (e.g., reaction with hydroxyl (OH)).⁶

Step 7: Summarize Emission Estimates

Actual CO₂ emissions in the United States were summarized by major fuel (i.e., coal, petroleum, natural gas, geothermal) and consuming sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories). Adjustments for international bunker fuels and carbon in non-energy products were made. Emission estimates are expressed in teragrams of carbon dioxide equivalents (Tg CO₂ Eq.).

To determine total emissions by final end-use sector, emissions from electricity generation were distributed to each end-use sector according to its share of aggregate electricity consumption (see Table 2-18). This pro-rated approach to allocating emissions from electricity generation may overestimate or underestimate emissions for particular sectors due to differences in the average carbon content of fuel mixes burned to generate electricity.

⁶ See the Indirect CO₂ from CH₄ Oxidation box in the Energy chapter for a discussion of accounting of carbon from hydrocarbon and CO emissions.

Table 2-1: 2002 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	97.0	1,368.3	NE	19,984.3	9.8	21,471.4	1.1	9.2	125.9	NE	1,868.4	0.9	2,005.6
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		97.0					97.0		9.2					9.2
Industrial Coking Coal			0.3				0.3			+				+
Industrial Other Coal			1,306.0				1,306.0			119.7				119.7
Coke Imports			62.1				62.1			6.3				6.3
Transportation Coal				NE			NE							NE
Utility Coal					19,984.3		19,984.3					1,868.4		1,868.4
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	5,061.0	3,208.0	8,242.4	666.0	5,665.1	23.1	22,865.6	267.2	169.4	423.7	35.2	299.1	1.2	1,195.7
Total Petroleum	1,521.4	736.6	9,182.2	25,643.9	902.8	624.6	38,611.5	104.7	52.7	406.1	1,729.2	72.2	44.4	2,409.4
Asphalt & Road Oil			1,240.0				1,240.0							
Aviation Gasoline				33.7			33.7				2.3			2.3
Distillate Fuel Oil	898.4	502.8	1,274.0	5,233.7	107.1	73.1	8,089.0	65.1	36.4	91.8	373.9	7.8	5.3	580.3
Jet Fuel				3,340.3		75.9	3,416.2				175.3		5.3	180.6
Kerosene	57.0	18.8	13.9			2.4	92.0	4.1	1.3	1.0			0.2	6.6
LPG	566.0	99.9	2,172.3	13.7		8.2	2,860.1	35.6	6.3	67.5	0.9		0.5	110.7
Lubricants			171.9	162.4		2.4	336.7			11.5	10.8		0.2	22.5
Motor Gasoline		38.5	303.1	16,219.9		186.4	16,747.9		2.7	21.3	1,138.7		13.1	1,175.8
Residual Fuel		76.4	222.2	640.2	671.3	130.3	1,740.4		6.0	15.1	27.3	51.9	10.2	110.5
Other Petroleum						146.0	146.0						9.7	9.7
AvGas Blend Components			7.3				7.3			0.5				0.5
Crude Oil														
MoGas Blend Components														
Misc. Products			131.1				131.1							
Naphtha (<401 deg. F)			569.3				569.3			13.4				13.4
Other Oil (>401 deg. F)			617.6				617.6			15.8				15.8
Pentanes Plus			218.7				218.7			7.2				7.2
Petroleum Coke		0.3	814.2		124.4		938.8		+	74.4		12.6		87.0
Still Gas			1,427.7				1,427.7			89.2				89.2
Special Naphtha			100.1				100.1			7.2				7.2
Unfinished Oils			(132.6)				(132.6)			(9.7)				(9.7)
Waxes			31.4				31.4							
Geothermal					45.6		45.6					0.3		0.3
TOTAL (All Fuels)	6,594.4	4,041.6	18,793.0	26,309.9	26,597.8	657.5	82,994.1	373.1	231.2	955.8	1,764.4	2,240.1	46.5	5,611.0

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-2: 2001 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	97.0	1,412.8	NE	19,558.0	9.8	21,089.6	1.1	9.2	129.0	NE	1,828.6	0.9	1,968.7
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		97.0					97.0		9.2					9.2
Industrial Coking Coal			14.3				14.3			0.3				0.3
Industrial Other Coal			1,355.6				1,355.6			124.3				124.3
Coke Imports			43.0				43.0			4.3				4.3
Transportation Coal				NE			NE							NE
Utility Coal					19,558.0		19,558.0					1,828.6		1,828.6
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	4,915.0	3,126.0	8,433.5	642.0	5,476.5	22.9	22,615.9	259.5	165.0	434.2	33.9	289.1	1.2	1,182.9
Total Petroleum	1,538.6	741.7	9,140.5	25,342.9	1,275.5	603.9	38,643.2	106.3	53.1	407.7	1,696.8	100.1	42.9	2,406.9
Asphalt & Road Oil			1,256.9				1,256.9							
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	908.3	508.4	1,288.2	5,291.7	161.1	70.6	8,228.4	65.8	36.8	92.9	378.0	11.7	5.1	590.2
Jet Fuel				3,426.0		73.9	3,499.9				181.0		5.2	186.2
Kerosene	95.1	31.4	23.2			2.3	152.0	6.8	2.2	1.7			0.2	10.9
LPG	535.2	94.5	2,054.1	12.9		8.0	2,704.7	33.7	5.9	64.1	0.8		0.5	105.0
Lubricants			174.0	164.3		2.3	340.6			11.6	11.0		0.2	22.7
Motor Gasoline		37.4	295.0	15,827.5		180.2	16,340.2		2.6	20.7	1,111.2		12.7	1,147.1
Residual Fuel		69.9	203.3	585.5	1,015.8	125.8	2,000.2		5.4	13.6	12.4	78.5	9.8	119.9
Other Petroleum						140.9	140.9						9.4	9.4
AvGas Blend Components			6.1				6.1			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products			124.9				124.9							
Naphtha (<401 deg. F)			493.7				493.7			11.9				11.9
Other Oil (>401 deg. F)			662.4				662.4			17.5				17.5
Pentanes Plus			263.2				263.2			9.0				9.0
Petroleum Coke		0.2	789.7		98.5		888.4		+	72.8		10.0		82.8
Still Gas			1,466.5				1,466.5			91.4				91.4
Special Naphtha			78.5				78.5			5.7				5.7
Unfinished Oils			(75.4)				(75.4)			(5.6)				(5.6)
Waxes			36.3				36.3							
Geothermal					46.9		46.9					0.4		0.4
TOTAL (All Fuels)	6,465.6	3,964.7	18,986.9	25,984.9	26,356.8	636.6	82,395.7	366.9	227.3	970.8	1,730.6	2,218.2	45.0	5,558.8

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-1).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-3: 2000 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	91.0	1,447.5	NE	20,219.8	9.8	21,780.1	1.1	8.6	133.8	NE	1,890.5	0.9	2,034.9
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Coking Coal			14.8				14.8			0.3				0.3
Industrial Other Coal			1,355.7				1,355.7			125.7				125.7
Coke Imports			77.0				77.0			7.8				7.8
Transportation Coal				NE			NE							NE
Utility Coal					20,219.8		20,219.8					1,890.5		1,890.5
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	5,121.0	3,301.3	9,189.2	672.0	5,317.7	12.7	23,613.9	270.3	174.3	473.8	35.5	280.7	0.7	1,235.3
Total Petroleum	1,563.1	756.4	9,022.3	25,612.5	1,151.4	624.6	38,730.2	107.8	54.2	392.1	1,714.2	90.4	44.4	2,403.0
Asphalt & Road Oil			1,275.7				1,275.7							
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	904.8	491.0	1,188.7	5,164.5	174.7	71.3	7,994.9	65.5	35.6	85.7	367.8	12.6	5.2	572.3
Jet Fuel				3,580.4		74.1	3,654.4				190.7		5.2	195.9
Kerosene	94.6	29.6	15.6			2.4	142.2	6.8	2.1	1.1			0.2	10.2
LPG	563.7	99.5	2,270.7	11.2		8.0	2,953.1	35.5	6.3	76.6	0.7		0.5	119.5
Lubricants			189.9	179.4		2.4	371.6			12.7	12.0		0.2	24.8
Motor Gasoline		44.5	150.2	15,753.2		186.6	16,134.6		3.1	10.5	1,105.9		13.1	1,132.7
Residual Fuel		91.6	240.6	887.5	882.2	130.9	2,232.8		7.1	16.6	34.6	68.2	10.2	136.7
Other Petroleum						149.1	149.1						9.9	9.9
AvGas Blend Components			3.8				3.8			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products			119.3				119.3			+				+
Naphtha (<401 deg. F)			613.9				613.9			16.4				16.4
Other Oil (>401 deg. F)			722.6				722.6			20.9				20.9
Pentanes Plus			343.4				343.4			13.4				13.4
Petroleum Coke		0.2	709.7		94.6		804.4		+	69.0		9.6		78.6
Still Gas			1,449.0				1,449.0			91.5				91.5
Special Naphtha			97.4				97.4			7.0				7.0
Unfinished Oils			(401.4)				(401.4)			(29.5)				(29.5)
Waxes			33.1				33.1			+				+
Geothermal					48.1		48.1					0.4		0.4
TOTAL (All Fuels)	6,696.1	4,148.7	19,658.9	26,284.5	26,737.0	647.1	84,172.3	379.3	237.1	999.7	1,749.6	2,261.9	45.9	5,673.6

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-4: 1999 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	14.0	103.0	1,419.3	NE	19,279.1	9.8	20,825.2	1.3	9.7	132.2	NE	1,802.5	0.9	1,946.6	
Residential Coal	14.0						14.0	1.3						1.3	
Commercial Coal		103.0					103.0		9.7					9.7	
Industrial Coking Coal			6.3				6.3			0.1				0.1	
Industrial Other Coal			1,343.0				1,343.0			125.0				125.0	
Coke Imports			70.0				70.0			7.1				7.1	
Transportation Coal				NE			NE							NE	
Utility Coal					19,279.1		19,279.1					1,802.5		1,802.5	
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9	
Natural Gas	4,858.0	3,130.0	9,040.6	674.0	4,923.5		22,626.2	256.5	165.2	466.2	35.6	259.9		1,183.4	
Total Petroleum	1,472.7	661.4	9,294.1	25,038.9	1,217.4	599.3	38,283.7	101.5	47.3	403.5	1,667.3	95.9	42.8	2,358.4	
Asphalt & Road Oil			1,324.4				1,324.4								
Aviation Gasoline				39.2			39.2				2.7			2.7	
Distillate Fuel Oil	827.8	438.4	1,175.5	5,001.0	140.0	80.8	7,663.5	59.9	31.8	84.7	353.9	10.1	5.9	546.3	
Jet Fuel				3,461.8			3,537.8				184.1		5.3	189.4	
Kerosene	111.2	26.9	12.8			3.7	154.7	8.0	1.9	0.9			0.3	11.1	
LPG	533.8	94.2	2,255.7	13.5		8.4	2,905.5	33.6	5.9	73.4	0.8		0.5	114.3	
Lubricants			192.8	182.1		1.4	376.3			12.9	12.1		0.1	25.1	
Motor Gasoline		28.4	151.7	15,675.9		178.5	16,034.5		2.0	10.6	1,099.9		12.5	1,125.1	
Residual Fuel		73.3	207.5	665.4	970.4	137.3	2,054.0		5.7	14.0	13.7	75.0	10.7	119.1	
Other Petroleum						113.1	113.1						7.5	7.5	
AvGas Blend Components			6.4				6.4			0.4				0.4	
Crude Oil															
MoGas Blend Components															
Misc. Products			111.9				111.9								
Naphtha (<401 deg. F)			502.0				502.0			13.5				13.5	
Other Oil (>401 deg. F)			811.0				811.0			23.6				23.6	
Pentanes Plus			364.9				364.9			13.9				13.9	
Petroleum Coke		0.1	845.7		106.9		952.8		+	75.7		10.8		86.5	
Still Gas			1,436.9				1,436.9			90.5				90.5	
Special Naphtha			145.4				145.4			10.5				10.5	
Unfinished Oils			(287.9)				(287.9)			(21.1)				(21.1)	
Waxes			37.4				37.4								
Geothermal					50.9		50.9					0.4		0.4	
TOTAL (All Fuels)	6,344.7	3,894.4	19,754.1	25,712.9	25,470.9	609.1	81,786.0	359.3	222.3	1,001.9	1,702.9	2,158.7	43.7	5,488.8	

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-5: 1998 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	13.0	92.0	1,483.9	NE	19,215.8	9.8	20,814.5	1.2	8.7	137.6	NE	1,796.6	0.9	1,945.0
Residential Coal	13.0						13.0	1.2						1.2
Commercial Coal		92.0					92.0		8.7					8.7
Industrial Coking Coal			15.4				15.4			0.4				0.4
Industrial Other Coal			1,388.5				1,388.5			129.2				129.2
Coke Imports			80.0				80.0			8.1				8.1
Transportation Coal				NE			NE							NE
Utility Coal					19,215.8		19,215.8					1,796.6		1,796.6
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	4,669.0	3,098.0	9,410.5	665.0	4,697.5		22,540.0	246.5	163.5	484.2	35.1	248.0		1,177.3
Total Petroleum	1,313.8	660.8	9,014.8	24,364.3	1,312.0	581.8	37,247.5	90.9	47.5	396.2	1,609.8	103.5	41.7	2,289.7
Asphalt & Road Oil			1,262.6				1,262.6							
Aviation Gasoline				35.5			35.5				2.4			2.4
Distillate Fuel Oil	771.9	428.8	1,199.8	4,811.5	135.8	90.0	7,437.9	55.9	31.1	86.5	336.9	9.8	6.5	526.7
Jet Fuel				3,356.8		76.0	3,432.8				178.4		5.3	183.7
Kerosene	108.3	31.2	22.1			6.0	167.5	7.8	2.2	1.6			0.4	12.0
LPG	433.6	76.5	2,048.3	16.6		5.9	2,580.9	27.3	4.8	65.2	1.0		0.4	98.6
Lubricants			190.8	180.2		1.3	372.3			12.7	12.0		0.1	24.8
Motor Gasoline		39.0	199.4	15,289.9		168.1	15,696.5		2.7	14.0	1,072.9		11.8	1,101.4
Residual Fuel		85.2	229.8	673.7	1,059.8	141.0	2,189.6		6.6	15.7	6.2	81.9	11.0	121.4
Other Petroleum						93.5	93.5						6.2	6.2
AvGas Blend Components			4.0				4.0			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products			119.0				119.0			+				+
Naphtha (<401 deg. F)			584.0				584.0			16.3				16.3
Other Oil (>401 deg. F)			818.7				818.7			24.8				24.8
Pentanes Plus			294.0				294.0			11.7				11.7
Petroleum Coke		0.1	769.4		116.4		885.9		+	71.5		11.8		83.3
Still Gas			1,437.3				1,437.3			91.4				91.4
Special Naphtha			107.3				107.3			7.7				7.7
Unfinished Oils			(313.9)				(313.9)			(23.1)				(23.1)
Waxes			42.4				42.4			+				+
Geothermal					50.4		50.4					0.4		0.4
TOTAL (All Fuels)	5,995.8	3,850.8	19,909.2	25,029.3	25,275.7	591.6	80,652.4	338.6	219.7	1,018.1	1,644.9	2,148.5	42.6	5,412.4

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-6: 1997 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	16.0	129.0	1,582.3	NE	18,904.2	10.4	20,641.9	1.5	12.2	145.8	NE	1,767.4	0.9	1,927.8
Residential Coal	16.0						16.0	1.5						1.5
Commercial Coal		129.0					129.0		12.2					12.2
Industrial Coking Coal			46.3				46.3			2.4				2.4
Industrial Other Coal			1,479.0				1,479.0			137.6				137.6
Coke Imports			57.0				57.0			5.8				5.8
Transportation Coal				NE			NE							NE
Utility Coal					18,904.2		18,904.2					1,767.4		1,767.4
U.S. Territory Coal (bit)						10.4	10.4						0.9	0.9
Natural Gas	5,118.0	3,302.0	9,592.7	779.0	4,146.6		22,938.2	270.2	174.3	496.1	41.1	218.9		1,200.6
Total Petroleum	1,428.1	703.9	9,191.7	23,759.0	931.1	580.0	36,593.8	98.9	50.7	416.6	1,573.6	73.7	41.6	2,255.2
Asphalt & Road Oil			1,223.6				1,223.6							
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	874.4	443.8	1,192.6	4,672.3	110.5	92.9	7,386.5	63.3	32.1	86.0	329.3	8.0	6.7	525.5
Jet Fuel				3,308.2			3,384.7				176.2		5.4	181.6
Kerosene	92.9	24.6	18.8			3.9	140.3	6.6	1.8	1.3			0.3	10.0
LPG	460.8	81.3	2,134.1	13.4		5.4	2,695.0	28.9	5.1	74.9	0.8		0.3	110.1
Lubricants			182.3	172.1		2.5	356.9			12.2	11.5		0.2	23.8
Motor Gasoline		42.7	211.8	14,841.6		164.8	15,260.9		3.0	14.9	1,042.5		11.6	1,071.9
Residual Fuel		111.2	290.6	711.7	723.4	143.9	1,980.9		8.7	20.5	10.6	55.9	11.2	107.0
Other Petroleum						90.0	90.0						6.0	6.0
AvGas Blend Components			9.1				9.1			0.6				0.6
Crude Oil			4.6				4.6			0.3				0.3
MoGas Blend Components														
Misc. Products			97.8				97.8			+				+
Naphtha (<401 deg. F)			536.4				536.4			15.5				15.5
Other Oil (>401 deg. F)			861.3				861.3			26.9				26.9
Pentanes Plus			328.9				328.9			10.7				10.7
Petroleum Coke		0.1	639.5		97.3		736.9		+	63.1		9.8		73.0
Still Gas			1,447.2				1,447.2			91.9				91.9
Special Naphtha			72.3				72.3			5.2				5.2
Unfinished Oils			(102.9)				(102.9)			(7.6)				(7.6)
Waxes			43.7				43.7			+				+
Geothermal					50.5		50.5					0.4		0.4
TOTAL (All Fuels)	6,562.1	4,134.9	20,366.7	24,538.0	24,032.4	590.4	80,224.4	370.6	237.2	1,058.4	1,614.8	2,060.5	42.6	5,384.0

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-7: 1996 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	17.0	122.0	1,573.4	NE	18,428.8	10.3	20,151.5	1.6	11.5	144.5	NE	1,722.2	0.9	1,880.7
Residential Coal	17.0						17.0	1.6						1.6
Commercial Coal		122.0					122.0		11.5					11.5
Industrial Coking Coal			59.7				59.7			3.5				3.5
Industrial Other Coal			1,478.7				1,478.7			137.5				137.5
Coke Imports			35.0				35.0			3.5				3.5
Transportation Coal				NE			NE							NE
Utility Coal					18,428.8		18,428.8					1,722.2		1,722.2
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9
Natural Gas	5,383.0	3,244.0	9,561.5	736.0	3,881.8		22,806.3	284.2	171.3	494.7	38.9	204.9		1,193.9
Total Petroleum	1,488.0	751.3	8,959.0	23,523.2	820.7	559.9	36,102.2	103.1	54.3	406.7	1,565.9	64.7	40.3	2,235.1
Asphalt & Road Oil			1,175.9				1,175.9							
Aviation Gasoline				37.4			37.4				2.6			2.6
Distillate Fuel Oil	926.0	482.9	1,177.6	4,469.3	109.3	95.1	7,260.3	67.1	35.0	84.9	315.4	7.9	6.9	517.2
Jet Fuel				3,274.2			3,347.2				177.6		5.1	182.7
Kerosene	88.8	21.0	18.3			3.0	131.1	6.4	1.5	1.3			0.2	9.4
LPG	473.2	83.5	2,088.9	14.7		5.7	2,666.1	29.7	5.2	70.3	0.9		0.4	106.5
Lubricants			172.5	163.0		0.8	336.3			11.5	10.9		0.1	22.4
Motor Gasoline		26.5	199.9	14,713.3		155.2	15,094.9		1.9	14.0	1,034.0		10.9	1,060.8
Residual Fuel		137.2	335.2	851.3	635.3	148.6	2,107.6		10.7	24.1	24.6	49.1	11.6	120.0
Other Petroleum						78.5	78.5						5.2	5.2
AvGas Blend Components			6.9				6.9			0.5				0.5
Crude Oil			13.7				13.7			1.0				1.0
MoGas Blend Components														
Misc. Products			89.0				89.0							
Naphtha (<401 deg. F)			478.9				478.9			13.1				13.1
Other Oil (>401 deg. F)			729.1				729.1			21.6				21.6
Pentanes Plus			354.7				354.7			11.2				11.2
Petroleum Coke		0.1	672.0		76.1		748.2		+	64.7		7.7		72.4
Still Gas			1,435.9				1,435.9			91.3				91.3
Special Naphtha			74.5				74.5			5.4				5.4
Unfinished Oils			(112.7)				(112.7)			(8.3)				(8.3)
Waxes			48.6				48.6							
Geothermal					50.2		50.2					0.4		0.4
TOTAL (All Fuels)	6,888.0	4,117.3	20,093.8	24,259.2	23,181.6	570.2	79,110.2	388.9	237.0	1,045.9	1,604.8	1,992.2	41.3	5,310.1

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-8: 1995 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Consumption (Tbtu) ^a					Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	17.0	117.0	1,606.8	NE	17,466.7	10.2	19,217.7	1.6	11.0	147.9	NE	1,632.3	0.9	1,793.8
Residential Coal	17.0						17.0	1.6						1.6
Commercial Coal		117.0					117.0		11.0					11.0
Industrial Coking Coal			50.6				50.6			2.6				2.6
Industrial Other Coal			1,495.2				1,495.2			139.1				139.1
Coke Imports			61.0				61.0			6.2				6.2
Transportation Coal				NE			NE							NE
Utility Coal					17,466.7		17,466.7					1,632.3		1,632.3
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,981.0	3,113.0	9,261.0	723.0	4,326.6		22,404.6	263.0	164.3	479.0	38.2	228.4		1,172.9
Total Petroleum	1,383.3	732.0	8,524.9	22,897.0	756.9	555.1	34,849.2	96.2	53.1	379.8	1,524.1	59.8	40.2	2,153.2
Asphalt & Road Oil			1,178.2				1,178.2							
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	904.8	478.9	1,123.0	4,195.0	108.2	112.6	6,922.3	65.5	34.7	81.0	294.7	7.8	8.2	491.9
Jet Fuel				3,132.2		71.7	3,203.9				168.7		5.0	173.8
Kerosene	74.3	22.1	15.4			3.5	115.3	5.3	1.6	1.1			0.2	8.3
LPG	404.2	71.3	2,019.4	16.7		5.2	2,517.0	25.4	4.5	69.1	1.1		0.3	100.4
Lubricants			177.8	167.9		2.0	347.7			11.9	11.2		0.1	23.2
Motor Gasoline		18.1	200.1	14,435.1		148.4	14,801.7		1.3	14.1	1,015.5		10.4	1,041.3
Residual Fuel		141.5	336.7	910.5	571.8	155.0	2,115.6		11.0	24.2	30.2	44.2	12.1	121.8
Other Petroleum						56.8	56.8						3.8	3.8
AvGas Blend Components			5.3				5.3			0.4				0.4
Crude Oil			14.5				14.5			1.1				1.1
MoGas Blend Components														
Misc. Products			97.0				97.0							
Naphtha (<401 deg. F)			372.6				372.6			10.4				10.4
Other Oil (>401 deg. F)			800.3				800.3			24.2				24.2
Pentanes Plus			337.6				337.6			10.8				10.8
Petroleum Coke		0.1	639.9		76.9		716.9		+	62.1		7.8		69.9
Still Gas			1,416.2				1,416.2			88.0				88.0
Special Naphtha			70.8				70.8			5.1				5.1
Unfinished Oils			(320.6)				(320.6)			(23.5)				(23.5)
Waxes			40.6				40.6							
Geothermal					48.8		48.8					0.4		0.4
TOTAL (All Fuels)	6,381.3	3,962.0	19,392.7	23,620.0	22,598.9	565.3	76,520.3	360.8	228.4	1,006.8	1,562.3	1,920.8	41.1	5,120.2

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-9: 1994 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	21.0	118.0	1,640.5	NE	17,260.6	10.0	19,050.1	2.0	11.1	151.1	NE	1,611.5	0.9	1,776.6
Residential Coal	21.0						21.0	2.0						2.0
Commercial Coal		118.0					118.0		11.1					11.1
Industrial Coking Coal			37.0				37.0			1.5				1.5
Industrial Other Coal			1,545.5				1,545.5			143.8				143.8
Coke Imports			58.0				58.0			5.9				5.9
Transportation Coal				NE			NE							NE
Utility Coal					17,260.6		17,260.6					1,611.5		1,611.5
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9
Natural Gas	4,988.0	2,979.0	8,780.4	708.0	3,999.6		21,455.1	263.3	157.3	453.4	37.4	211.1		1,122.6
Total Petroleum	1,420.2	787.5	8,713.5	22,442.4	1,063.0	561.8	34,988.4	99.0	57.3	398.5	1,498.2	83.2	40.8	2,176.9
Asphalt & Road Oil			1,172.9				1,172.9							
Aviation Gasoline				38.1			38.1				2.6			2.6
Distillate Fuel Oil	959.8	500.9	1,103.7	4,032.0	119.8	118.8	6,835.0	69.5	36.3	79.7	283.2	8.7	8.6	486.0
Jet Fuel				3,154.5		65.8	3,220.3				173.2		4.6	177.9
Kerosene	64.9	19.5	16.9			3.0	104.3	4.6	1.4	1.2			0.2	7.5
LPG	395.4	69.8	1,996.5	32.2		7.3	2,501.2	24.8	4.4	70.8	2.0		0.5	102.5
Lubricants			180.9	170.8		1.9	353.6			12.1	11.4		0.1	23.6
Motor Gasoline		25.2	192.4	14,132.1		148.0	14,497.7		1.8	13.6	997.8		10.5	1,023.6
Residual Fuel		171.9	418.9	882.6	876.5	164.1	2,514.1		13.4	30.7	27.9	67.7	12.8	152.6
Other Petroleum						53.0	53.0						3.5	3.5
AvGas Blend Components			6.1				6.1			0.4				0.4
Crude Oil			18.7				18.7			1.4				1.4
MoGas Blend Components														
Misc. Products			105.9				105.9			+				+
Naphtha (<401 deg. F)			398.4				398.4			11.6				11.6
Other Oil (>401 deg. F)			838.7				838.7			26.3				26.3
Pentanes Plus			338.7				338.7			12.9				12.9
Petroleum Coke		0.1	643.0		66.7		709.8		+	62.2		6.7		68.9
Still Gas			1,439.5				1,439.5			90.4				90.4
Special Naphtha			81.1				81.1			5.8				5.8
Unfinished Oils			(279.2)				(279.2)			(20.5)				(20.5)
Waxes			40.6				40.6			+				+
Geothermal					45.7		45.7					0.3		0.3
TOTAL (All Fuels)	6,429.2	3,884.5	19,134.5	23,150.4	22,369.0	571.8	75,539.4	364.3	225.6	1,003.1	1,535.6	1,906.1	41.7	5,076.4

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-10: 1993 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	24.0	119.0	1,608.4	NE	17,196.1	9.6	18,957.1	2.3	11.2	147.7	NE	1,604.7	0.9	1,766.7
Residential Coal	24.0						24.0	2.3						2.3
Commercial Coal		119.0					119.0		11.2					11.2
Industrial Coking Coal			38.3				38.3			1.5				1.5
Industrial Other Coal			1,543.1				1,543.1			143.4				143.4
Coke Imports			27.0				27.0			2.7				2.7
Transportation Coal				NE			NE							NE
Utility Coal					17,196.1		17,196.1					1,604.7		1,604.7
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9
Natural Gas	5,095.0	2,942.0	8,740.3	644.0	3,559.4		20,980.7	269.0	155.3	453.8	34.0	187.9		1,099.9
Total Petroleum	1,448.0	779.9	8,327.9	21,927.6	1,130.2	534.1	34,147.7	101.0	56.7	387.0	1,459.3	88.7	38.7	2,131.3
Asphalt & Road Oil			1,149.0				1,149.0							
Aviation Gasoline				38.4			38.4				2.6			2.6
Distillate Fuel Oil	973.8	493.0	1,109.9	3,795.8	86.5	104.9	6,564.0	70.5	35.7	80.1	264.3	6.3	7.6	464.5
Jet Fuel				3,028.0		62.1	3,090.1				165.5		4.4	169.8
Kerosene	75.6	14.0	13.1			3.8	106.5	5.4	1.0	0.9			0.3	7.6
LPG	398.6	70.3	1,794.4	19.0		4.9	2,287.2	25.0	4.4	66.5	1.2		0.3	97.5
Lubricants			173.1	163.5		3.3	339.8			11.5	10.9		0.2	22.7
Motor Gasoline		29.6	179.5	13,981.4		128.3	14,318.8		2.1	12.7	986.1		9.0	1,009.9
Residual Fuel		172.7	445.9	901.5	969.6	155.9	2,645.5		13.5	32.7	28.7	74.9	12.2	161.9
Other Petroleum						71.0	71.0						4.7	4.7
AvGas Blend Components			0.1				0.1			+				+
Crude Oil			21.1				21.1			1.6				1.6
MoGas Blend Components														
Misc. Products			94.7				94.7							
Naphtha (<401 deg. F)			350.5				350.5			10.6				10.6
Other Oil (>401 deg. F)			843.9				843.9			27.5				27.5
Pentanes Plus			332.2				332.2			12.1				12.1
Petroleum Coke		0.2	642.0		74.2		716.3		+	62.9		7.5		70.4
Still Gas			1,429.8				1,429.8			89.4				89.4
Special Naphtha			104.6				104.6			7.5				7.5
Unfinished Oils			(395.9)				(395.9)			(29.1)				(29.1)
Waxes			40.0				40.0							
Geothermal					52.9		52.9					0.4		0.4
TOTAL (All Fuels)	6,567.0	3,840.9	18,676.6	22,571.6	21,938.7	543.7	74,138.4	372.2	223.2	988.4	1,493.3	1,881.7	39.5	4,998.3

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-11: 1992 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	24.0	118.0	1,592.5	NE	16,465.3	8.8	18,208.6	2.3	11.2	146.6	NE	1,535.7	0.8	1,696.6
Residential Coal	24.0						24.0	2.3						2.3
Commercial Coal		118.0					118.0		11.2					11.2
Industrial Coking Coal			24.9				24.9			0.6				0.6
Industrial Other Coal			1,532.6				1,532.6			142.5				142.5
Coke Imports			35.0				35.0			3.5				3.5
Transportation Coal				NE			NE							NE
Utility Coal					16,465.3		16,465.3					1,535.7		1,535.7
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8
Natural Gas	4,835.0	2,890.0	8,583.3	608.0	3,534.8		20,451.1	255.2	152.6	446.3	32.1	186.6		1,072.8
Total Petroleum	1,427.2	854.0	8,485.7	21,656.6	997.3	507.5	33,928.3	99.6	62.1	407.3	1,430.9	77.7	36.8	2,114.4
Asphalt & Road Oil			1,102.2				1,102.2							
Aviation Gasoline				41.1			41.1				2.8			2.8
Distillate Fuel Oil	979.7	506.7	1,100.1	3,683.9	73.5	91.8	6,435.6	70.9	36.7	79.4	256.2	5.3	6.6	455.2
Jet Fuel				3,001.3		61.3	3,062.6				164.3		4.3	168.6
Kerosene	65.0	11.1	9.8			3.3	89.2	4.7	0.8	0.7			0.2	6.4
LPG	382.5	67.5	1,859.8	18.3		11.9	2,340.1	24.0	4.2	70.8	1.2		0.7	100.9
Lubricants			170.0	160.5		1.5	332.0			11.3	10.7		0.1	22.1
Motor Gasoline		79.6	194.2	13,681.4		122.1	14,077.4		5.6	13.7	964.5		8.6	992.4
Residual Fuel		189.1	386.9	1,070.0	881.3	154.6	2,681.8		14.8	27.9	31.2	68.1	12.1	154.0
Other Petroleum						61.2	61.2						4.0	4.0
AvGas Blend Components			0.2				0.2			+				+
Crude Oil			27.4				27.4			2.0				2.0
MoGas Blend Components			75.7				75.7			5.3				5.3
Misc. Products			100.1				100.1			+				+
Naphtha (<401 deg. F)			377.3				377.3			11.8				11.8
Other Oil (>401 deg. F)			815.0				815.0			27.6				27.6
Pentanes Plus			322.7				322.7			19.2				19.2
Petroleum Coke		0.1	709.5		42.6		752.2		+	64.5		4.3		68.8
Still Gas			1,447.8				1,447.8			91.5				91.5
Special Naphtha			104.6				104.6			7.5				7.5
Unfinished Oils			(355.0)				(355.0)			(26.1)				(26.1)
Waxes			37.3				37.3			+				+
Geothermal					57.3		57.3					0.4		0.4
TOTAL (All Fuels)	6,286.2	3,862.0	18,661.5	22,264.6	21,054.7	516.4	72,645.3	357.1	225.9	1,000.2	1,463.0	1,800.5	37.6	4,884.2

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-12: 1991 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	23.0	118.0	1,621.3	NE	16,249.7	7.7	18,019.8	2.2	11.1	149.4	NE	1,515.6	0.7	1,679.1
Residential Coal	23.0						23.0	2.2						2.2
Commercial Coal		118.0					118.0		11.1					11.1
Industrial Coking Coal			28.5				28.5			1.4				1.4
Industrial Other Coal			1,582.9				1,582.9			147.1				147.1
Coke Imports			10.0				10.0			1.0				1.0
Transportation Coal				NE			NE							NE
Utility Coal					16,249.7		16,249.7					1,515.6		1,515.6
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	4,697.0	2,813.0	8,247.2	620.0	3,399.1		19,776.3	248.0	148.5	428.1	32.7	179.4		1,036.7
Total Petroleum	1,392.2	905.2	7,892.4	21,358.8	1,206.1	539.8	33,294.4	97.0	66.0	374.0	1,398.9	93.5	38.6	2,067.9
Asphalt & Road Oil			1,076.5				1,076.5							
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	930.4	517.4	1,070.8	3,600.6	83.6	71.4	6,274.1	67.4	37.5	77.3	249.9	6.1	5.2	443.3
Jet Fuel				3,025.0		78.2	3,103.2				166.5		5.5	172.0
Kerosene	72.3	12.1	11.4			2.8	98.6	5.2	0.9	0.8			0.2	7.1
LPG	389.5	68.7	1,749.3	19.9		13.8	2,241.2	24.5	4.3	67.5	1.3		0.9	98.3
Lubricants			166.7	157.5		0.6	324.8			11.1	10.5		+	21.7
Motor Gasoline		85.1	193.3	13,488.2		124.7	13,891.2		6.0	13.6	950.4		8.8	978.8
Residual Fuel		221.9	333.9	1,025.9	1,094.9	134.6	2,811.3		17.3	23.6	17.5	84.6	10.5	153.5
Other Petroleum						113.8	113.8						7.5	7.5
AvGas Blend Components			(0.1)				(0.1)			(+)				(+)
Crude Oil			38.9				38.9			2.9				2.9
MoGas Blend Components			(25.9)				(25.9)			(1.8)				(1.8)
Misc. Products			152.6				152.6							
Naphtha (<401 deg. F)			298.9				298.9			10.1				10.1
Other Oil (>401 deg. F)			827.2				827.2			30.1				30.1
Pentanes Plus			294.0				294.0			18.0				18.0
Petroleum Coke			605.6		27.6		633.1			57.9		2.8		60.7
Still Gas			1,426.3				1,426.3			89.5				89.5
Special Naphtha			88.0				88.0			6.3				6.3
Unfinished Oils			(450.1)				(450.1)			(33.0)				(33.0)
Waxes			35.1				35.1							
Geothermal					54.9		54.9					0.4		0.4
TOTAL (All Fuels)	6,112.2	3,836.2	17,760.9	21,978.8	20,909.8	547.5	71,145.4	347.1	225.6	951.5	1,431.6	1,788.9	39.3	4,784.1

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-13: 1990 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	26.0	129.0	1,633.0	NE	16,260.7	7.0	18,055.8	2.4	12.1	150.3	NE	1,515.9	0.6	1,681.4
Residential Coal	26.0						26.0	2.4						2.4
Commercial Coal		129.0					129.0		12.1					12.1
Industrial Coking Coal			21.0				21.0			0.5				0.5
Industrial Other Coal			1,607.0				1,607.0			149.2				149.2
Coke Imports			5.0				5.0			0.5				0.5
Transportation Coal				NE			NE							NE
Utility Coal					16,260.7		16,260.7					1,515.9		1,515.9
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6
Natural Gas	4,523.0	2,701.0	8,133.9	680.0	3,333.0		19,370.9	238.8	142.6	421.6	35.9	176.0		1,014.8
Total Petroleum	1,407.0	953.1	8,183.2	21,606.5	1,292.6	461.5	33,904.0	98.3	69.5	394.7	1,422.3	100.1	33.1	2,118.0
Asphalt & Road Oil			1,170.2				1,170.2							
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	978.1	535.8	1,143.4	3,661.1	96.5	74.0	6,489.0	70.8	38.8	82.6	253.7	7.0	5.4	458.2
Jet Fuel				3,129.5		61.0	3,190.5				173.8		4.3	178.1
Kerosene	63.9	11.8	12.3			2.6	90.6	4.6	0.8	0.9			0.2	6.5
LPG	365.0	64.4	1,607.8	21.6		14.4	2,073.3	22.9	4.0	63.4	1.4		0.9	92.6
Lubricants			186.3	176.0		0.7	363.0			12.4	11.7		+	24.2
Motor Gasoline		111.2	185.2	13,557.2		101.0	13,954.7		7.8	13.0	955.2		7.1	983.2
Residual Fuel		229.8	411.4	1,016.0	1,167.3	121.8	2,946.5		17.9	30.3	23.4	90.2	9.5	171.3
Other Petroleum						86.0	86.0						5.7	5.7
AvGas Blend Components			0.2				0.2			+				+
Crude Oil			50.9				50.9			3.7				3.7
MoGas Blend Components			53.7				53.7			3.8				3.8
Misc. Products			137.9				137.9			+				+
Naphtha (<401 deg. F)			347.9				347.9			11.6				11.6
Other Oil (>401 deg. F)			754.2				754.2			27.2				27.2
Pentanes Plus			250.4				250.4			13.9				13.9
Petroleum Coke			626.2		28.8		655.0			58.7		2.9		61.6
Still Gas			1,473.7				1,473.7			92.6				92.6
Special Naphtha			107.1				107.1			7.7				7.7
Unfinished Oils			(369.1)				(369.1)			(27.0)				(27.0)
Waxes			33.3				33.3			+				+
Geothermal					52.9		52.9					0.4		0.4
TOTAL (All Fuels)	5,956.0	3,783.1	17,950.1	22,286.5	20,939.2	468.6	71,383.5	339.6	224.2	966.6	1,458.2	1,792.4	33.7	4,814.7

^a Expressed as gross calorific values (i.e., higher heating values).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

^c Adjustments include: international bunker fuel consumption (see Table 2-14) and carbon in non-energy products (see Table 2-15).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table 2-14: 2002 CO₂ Emissions From International Bunker Fuel Consumption

Fuel Type	Bunker Fuel Consumption (TBtu)	Carbon Content Coefficient (Tg Carbon/QBtu) ¹	Potential Emissions (Tg Carbon)	Fraction Oxidized	Emissions (Tg CO ₂ Eq.)
Distillate Fuel Oil	70	19.95	1.4	0.99	5.1
Jet Fuel	843	19.33	16.3	0.99	59.1
Residual Fuel Oil	290	21.49	6.2	0.99	22.6
Total	1,203		23.9		86.8

Note: See Annex 3.7 for additional information on military bunkers.

Table 2-15: 2002 Carbon In Non-Energy Products

1	2	3	4	5	6	7	8
Fuel Type	Non-energy Use ^a (TBtu)	Carbon Content Coefficient (Tg Carbon/QBtu)	Potential Carbon (Tg)	Adjusted Potential Carbon ^b (Tg)	Fraction Sequestered	Carbon Stored (Tg)	Carbon Stored (Tg CO ₂ Eq.)
Industry	5,318.0		99.8	97.2		70.5	258.4
Industrial Coking Coal	0.3	25.56	+	+	0.75	+	+
Natural Gas	339.2	14.47	4.9	4.6	0.67	3.1	11.5
Asphalt & Road Oil	1,240.0	20.62	25.6	25.6	1.00	25.6	93.7
LPG	1,690.6	16.81	28.4	27.1	0.67	18.2	66.8
Lubricants	171.9	20.24	3.5	3.5	0.09	0.3	1.2
Pentanes Plus	171.4	18.24	3.1	3.0	0.67	2.0	7.4
Petrochemical Feedstocks							
Naphtha (<401 deg. F)	569.3	18.14	10.3	9.9	0.67	6.6	24.4
Other Oil (>401 deg. F)	617.6	19.95	12.3	11.8	0.67	8.0	29.2
Still Gas	30.3	17.51	0.5	0.5	0.80	0.4	1.6
Petroleum Coke	156.6	27.85	4.4	4.4	0.50	2.2	8.0
Special Naphtha	100.1	19.86	2.0	2.0	0.00	+	+
Other (Wax/Misc.)							
Distillate Fuel Oil	11.7	19.95	0.2	0.2	0.50	0.1	0.4
Residual Fuel	56.6	21.49	1.2	1.2	0.50	0.6	2.2
Waxes	31.4	19.81	0.6	0.6	1.00	0.6	2.3
Miscellaneous	131.1	20.23	2.7	2.7	1.00	2.7	9.7
Transportation	162.4		3.3	3.3		0.3	1.1
Lubricants	162.4	20.24	3.3	3.3	0.09	0.3	1.1
U.S. Territories	148.3		3.0	3.0		0.3	1.1
Lubricants	2.4	20.24	+	+	0.09	+	+
Other Petroleum (Misc.)	146.0	20.00	2.9	2.9	0.10	0.29	1.1
Total	5,628.7		106.0	103.4		71.1	260.6

^a To avoid double-counting, the original values reported by EIA for coal coke, petroleum coke, and natural gas consumption are adjusted for industrial process consumption. Values in this column reflect these adjustments.

^b Natural gas, LPG, Pentanes Plus, Naphthas, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. Values in this column reflect these adjustments.

+ Does not exceed 0.05 Tg or Tg CO₂ Eq.

¹ One QBtu is one quadrillion Btu, or 10¹⁵ Btu. This unit is commonly referred to as a "Quad."

Table 2-16: Key Assumptions for Estimating Carbon Dioxide Emissions

Fuel Type	Carbon Content Coefficient (Tg Carbon/QBtu)	Fraction Oxidized
Coal		
Residential Coal	[a]	0.99
Commercial Coal	[a]	0.99
Industrial Coking Coal	[a]	0.99
Industrial Other Coal	[a]	0.99
Coke Imports	27.85	0.99
Transportation Coal	NC	NC
Utility Coal	[a]	0.99
U.S. Territory Coal (bit)	25.14	0.99
Natural Gas	14.47	0.995
Petroleum		
Asphalt & Road Oil	20.62	0.99
Aviation Gasoline	18.87	0.99
Distillate Fuel Oil	19.95	0.99
Jet Fuel	[a]	0.99
Kerosene	19.72	0.99
LPG (energy use)	[a]	0.995
LPG (non-energy use)	[a]	-
Lubricants	20.24	0.99
Motor Gasoline	[a]	0.99
Residual Fuel Oil	21.49	0.99
Other Petroleum		
AvGas Blend Components	18.87	0.99
Crude Oil	[a]	0.99
MoGas Blend Components	[a]	0.99
Misc. Products	[a]	0.99
Misc. Products (Territories)	20.00	0.99
Naphtha (<401 deg. F)	18.14	0.99
Other Oil (>401 deg. F)	19.95	0.99
Pentanes Plus	18.24	0.99
Petrochemical Feedstocks	19.37	0.99
Petroleum Coke	27.85	0.99
Still Gas	17.51	0.99
Special Naphtha	19.86	0.99
Unfinished Oils	[a]	0.99
Waxes	19.81	0.99
Geothermal	2.05	1.00

Sources: Carbon coefficients from EIA. Combustion efficiency for coal from Bechtel (1993) and for petroleum and natural gas from IPCC (IPCC/UNEP/OECD/IEA 1997).

- Not applicable

NC (Not Calculated)

[a] These coefficients vary annually due to fluctuations in fuel quality (see Table 2-17).

Table 2-17: Annually Variable Carbon Content Coefficients by Year (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Residential Coal	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Commercial Coal	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Industrial Coking Coal	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56
Industrial Other Coal	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63
Utility Coal ^a	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76
LPG (energy use)	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.26	17.25	17.24
LPG (non-energy use)	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.79	16.82	16.81
Motor Gasoline	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33
MoGas Blend Components	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34
Misc. Products	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23
Unfinished Oils	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23
Crude Oil	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23

^aCarbon content for utility coal used in the electric power calculations.

Source: EIA (2003a)

Table 2-18: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Residential	924	955	936	995	1,008	1,043	1,083	1,076	1,130	1,145	1,192	1,203	1,268
Commercial	838	855	850	885	913	953	980	1,027	1,078	1,104	1,159	1,197	1,208
Industrial	1,060	1,065	1,095	1,105	1,142	1,157	1,179	1,187	1,212	1,241	1,248	1,148	1,179
Transportation	5	5	5	5	5	5	5	5	5	5	5	6	5
Total	2,827	2,880	2,886	2,989	3,069	3,157	3,247	3,294	3,425	3,495	3,605	3,554	3,660

Note: Does not include the U.S. territories.

Source: EIA (2003a)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This annex presents the background and methodology for estimating the carbon content of fossil fuels combusted in the United States. The carbon content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all carbon in the fuel is oxidized during combustion. The carbon content coefficients used in this report were developed using methods first outlined in EIA's *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. This annex describes an updated methodology for estimating the carbon content of coal, and presents a time-series analysis of changes in U.S. carbon content coefficients. A summary of carbon content coefficients used in this report appears in Table 2-19.

Though the methods for estimating carbon contents for coal, natural gas, and petroleum products differ in their details, they each follow the same basic approach. First, because carbon coefficients are presented in terms of mass per unit energy (i.e., teragrams carbon per quadrillion Btu or Tg/QBtu), those fuels that are typically described in volumetric units (petroleum products and natural gas) are converted to units of mass using an estimated density. Second, carbon contents are derived from fuel sample data, using descriptive statistics to estimate the carbon share of the fuel by weight. The heat content of the fuel is then estimated based on the sample data, or where sample data are unavailable or unrepresentative, by default values that reflect the characteristics of the fuel as defined by market requirements. A discussion of each fuel appears below.

The carbon content of coal is described first because approximately one-third of all U.S. carbon emissions from fossil fuel combustion are associated with coal consumption. The methods and sources for estimating the carbon content of natural gas are provided next. Approximately one-fifth of U.S. greenhouse gas emissions from fossil fuel combustion are attributable to natural gas consumption. Finally, this annex examines carbon contents of petroleum products. U.S. energy consumption statistics account for more than 20 different petroleum products.

Table 2-19: Carbon Content Coefficients Used in this Report (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Coal													
Residential Coal ^a	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Commercial Coal ^a	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Industrial Coking Coal ^a	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56
Industrial Other Coal ^a	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63
Utility Coal ^{ab}	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76
Natural Gas	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47
Petroleum													
Asphalt and Road Oil	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62
Aviation Gasoline	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Distillate Fuel Oil	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Jet Fuel ^a	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33
Kerosene	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72
LPG (energy use) ^a	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.26	17.25	17.24
LPG (non-energy use) ^a	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.79	16.82	16.81
Lubricants	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24
Motor Gasoline ^a	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34
Residual Fuel	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Other Petroleum													
Av Gas Blend Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo Gas Blend Comp ^a	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.34
Crude Oil ^a	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23
Misc. Products ^a	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23
Misc. Products (Terr.)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Naphtha (<401 deg. F)	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14
Other oil (>401 deg. F)	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Pentananes Plus	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24
Petrochemical Feed.	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51
Special Naphtha	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86
Unfinished Oils ^a	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.23
Waxes	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81

Other Wax and Misc.	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81
Geothermal	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05

^aCarbon contents vary annually based on changes in fuel composition.

^bCarbon content for utility coal used in the electric power calculations.

All coefficients based on higher heating value.¹

Coal

Approximately one-third of all U.S. carbon dioxide emissions from fossil fuel combustion are associated with coal consumption. Although the IPCC guidelines provide carbon contents for coal according to rank, it was necessary to develop carbon content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the carbon content of coal varies by the state in which it was mined and by coal rank, and because the sources of coal for each consuming sector vary by year, the weighted average carbon content for coal combusted in each consuming sector also varies over time. A time series of carbon contents by coal rank and consuming sector appears in Table 2-20.²

Table 2-20: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg/QBtu) (1990-2002)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Electric Power	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Coal Rank													
Anthracite	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26 ^p
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49	25.49	25.49 ^p
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48	26.48	26.48 ^p
Lignite	26.19	26.21	26.22	26.21	26.24	26.22	26.17	26.20	26.23	26.26	26.30	26.30	26.30 ^p

^p Preliminary

Sources: Carbon content coefficients by consuming sector from EIA (2003). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2002).

Methodology

The methodology for developing carbon contents for coal by consuming sector consists of four steps.

Step 1. Determine carbon contents by rank and by state of origin

Carbon contents by rank are estimated on the basis of 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989. These coal samples are classified according to rank and state of origin. For each rank in each state, the average heat content and carbon content of the coal samples are calculated. Dividing the carbon content (reported in pounds carbon dioxide) by the heat content (reported in million Btu or MMBtu) yields an average carbon content coefficient. This coefficient is then converted into units of Tg/QBtu.

Step 2. Allocate sectoral consumption by rank and state of origin

U.S. energy statistics provide data on the origin of coal used in four areas: 1) the electric power industry, 2) industrial coking, 3) all other industrial uses, and 4) the residential and commercial end-use sectors. Because U.S.

¹ Higher heating value (gross heating value) is the total amount of heat released when a fuel is burned. Coal, crude oil, and natural gas all include chemical compounds of carbon and hydrogen. When those fuels are burned, the carbon and hydrogen combine with oxygen in the air to produce carbon dioxide and water. Some of the energy released in burning goes into transforming the water into steam and is usually lost. The amount of heat spent in transforming the water into steam is counted as part of gross heat content. Lower heating value (net heating value), in contrast, does not include the heat spent in transforming the water into steam. Using a simplified methodology based on International Energy Agency defaults, higher heating value can be converted to lower heating value for coal and petroleum products by multiplying by 0.95 and for natural gas by multiplying by 0.90. Carbon content coefficients are presented in higher heating value because U.S. energy statistics are reported by higher heating value.

² For a comparison to earlier estimated carbon contents please see *Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels* near the end of this annex.

energy statistics do not provide the distribution of coal rank consumed by each consuming sector, it is assumed that each sector consumes a representative mixture of coal ranks from a particular state that matches the mixture of all coal produced in that state during the year.

Step 3. Weight sectoral carbon contents to reflect the rank and state of origin of coal consumed

Sectoral carbon contents are calculated by multiplying the share of coal purchased from each state by rank by the carbon content estimated in Step 1. The resulting partial carbon contents are then totaled across all states and ranks to generate a national sectoral carbon content.

$$C_{\text{sector}} = \sum S_{\text{rank1}} * C_{\text{rank1}} + S_{\text{rank2}} * C_{\text{rank2}} + \dots S_{\text{rank50}} * C_{\text{rank50}}$$

Where:

C_{sector} is the carbon content by consuming sector;

S_{rank} is the portion of consuming sector coal consumption attributed to a given rank in each state; and

C_{rank} is the estimated carbon content of a given rank in each state.

Step 4. Develop national-level carbon contents by rank for comparison to IPCC defaults

Although not used to calculate emissions, national-level carbon contents by rank are more easily compared to carbon contents of other countries than are sectoral carbon contents. This step requires weighting the state-level carbon contents by rank developed under Step 1 by overall coal production by state and rank (consumption by rank is unavailable in U.S. energy statistics). Each state-level carbon content by rank is multiplied by the share of national production of that rank that each state represents. The resulting partial carbon contents are then summed across all states to generate an overall carbon content for each rank.

$$N_{\text{rank}} = \sum P_{\text{rank1}} * C_{\text{rank1}} + P_{\text{rank2}} * C_{\text{rank2}} + \dots P_{\text{rankn}} * C_{\text{rankn}}$$

Where:

N_{rank} is the national carbon content by rank;

P_{rank} is the portion of U.S. coal production attributed to a given rank in each state; and

C_{rank} is the estimated carbon content of a given rank in each state.

Data Sources

The ultimate analysis of coal samples was based on the 6,588 coal samples from the U.S. Geological Survey, CoalQual Database Version 2.0 (1998). Data contained in the CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys.

Data on coal distribution by state and consumption by sector, as well as coal production by state and rank, was obtained from EIA's *Coal Industry Annual* (2002).

Uncertainty

Carbon contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 53.4 percent and 38.1 percent of total U.S. supply in 2000, respectively. Carbon content coefficients for bituminous coal vary from a low of 200.5 pounds carbon dioxide per MMBtu in Kansas to a high of 232.0 pounds carbon dioxide per MMBtu in Montana. In 2000, however, just 200 tons of bituminous coal was produced in Kansas, and none was produced in Montana. In 2000, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky, and Pennsylvania, and this share has remained fairly constant since 1990. These three states show a variation in carbon content for bituminous coals of ± 0.7 percent, based on more than 2,000 samples (see Table 2-21).

Similarly, the carbon content coefficients for sub-bituminous coal range from 201.3 pounds carbon dioxide per MMBtu in Utah to 217.5 pounds carbon dioxide per MMBtu in Washington. Utah showed no sub-bituminous

coal production in 2000, and Washington produced just 4,000 tons. Wyoming, however, has represented between 75 percent and 82 percent of total sub-bituminous coal production in the United States since 1990. Thus, the carbon content coefficient for Wyoming, based on 435 samples, dominates.

The interquartile range of carbon content coefficients among samples of sub-bituminous coal in Wyoming was ± 1.5 percent from the mean. Similarly, this range among samples of bituminous coal from West Virginia, Kentucky, and Pennsylvania was ± 1.0 percent or less for each state. The large number of samples and the low variability within the sample set of the states that represent the predominant source of supply for U.S. coal suggest that the uncertainty in this factor is very low, on the order of ± 1.0 percent.

Table 2-21: Variability in Carbon Content Coefficients by Rank Across States (Kilograms Carbon Dioxide Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	946	92.85	-	-	99.11
Alaska	90	98.34	98.11	-	98.66
Arizona	11	-	97.52	-	-
Arkansas	70	96.52	-	-	94.98
Colorado	292	94.39	96.48	-	96.48
Georgia	35	95.03	-	-	-
Idaho	1	-	94.89	-	-
Illinois	16	93.35	-	-	-
Indiana	125	92.67	-	-	-
Iowa	89	91.94	-	-	-
Kansas	28	90.94	-	-	-
Kentucky	870	92.58	-	-	-
Louisiana	1	-	-	-	96.03
Maryland	46	94.35	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	92.85	-	-	-
Mississippi	8	-	-	-	98.20
Missouri	91	91.85	-	-	-
Montana	301	105.23	97.75	103.60	99.38
Nevada	2	94.39	-	-	99.84
New Mexico	167	95.25	94.89	103.92	-
North Dakota	186	-	-	-	99.56
Ohio	646	91.85	-	-	-
Oklahoma	46	92.67	-	-	-
Pennsylvania	739	93.39	-	103.65	-
Tennessee	58	92.80	-	-	-
Texas	48	-	-	-	94.76
Utah	152	96.07	91.31	-	-
Virginia	456	93.53	-	98.52	-
Washington	14	95.39	98.66	102.51	106.55
West Virginia	566	93.89	-	-	-
Wyoming	476	94.66	97.20	-	-

- No Sample Data Available

Sources: USGS (1998) and SAIC (2002).

Natural Gas

Natural gas is predominantly composed of methane, which is 75 percent carbon by weight and contains 14.2 Tg C/QBtu (Higher Heating Value), but it may also contain many other compounds that can lower or raise its overall carbon content. These other compounds may be divided into two classes: 1) natural gas liquids (NGLs), and 2) non-hydrocarbon gases. The most common NGLs are ethane (C₂H₆), propane (C₃H₈), butane (C₄H₁₀), and, to a lesser extent, pentane (C₅H₁₂) and hexane (C₆H₁₄). Because the NGLs have more carbon atoms than methane (which has only one), their presence increases the overall carbon content of natural gas. NGLs have a commercial value greater than that of methane, and therefore are usually separated from raw natural gas at gas processing plants and sold as separate products. Ethane is typically used as a petrochemical feedstock, propane and butane have

diverse uses, and natural gasoline³ contributes to the gasoline/naphtha "octane pool," used primarily to make motor gasoline.

Raw natural gas can also contain varying amounts of non-hydrocarbon gases, such as carbon dioxide, nitrogen, helium and other noble gases, and hydrogen sulfide. The share of non-hydrocarbon gases is usually less than 5 percent of the total, but there are individual natural gas reservoirs where the share can be much larger. The treatment of non-hydrocarbon gases in raw gas varies. Hydrogen sulfide is always removed. Inert gases are removed if their presence is substantial enough to reduce the energy content of the gas below pipeline specifications. Otherwise, inert gases will usually be left in the natural gas. Because the raw gas that is usually flared contains NGLs and carbon dioxide, it will typically have a higher overall carbon content than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Methodology

The methodology for estimating the carbon contents of natural gas can be described in five steps.

Step 1. Define pipeline-quality natural gas

In the United States, pipeline-quality natural gas is expected to have an energy content greater than 970 Btu per cubic foot, but less than 1,100 Btu per cubic foot. Hydrogen sulfide content must be negligible. Typical pipeline-quality natural gas is about 95 percent methane, 3 percent NGLs, and 2 percent non-hydrocarbon gases, of which approximately 1 percent is carbon dioxide.

However, there is a range of gas compositions that are consistent with pipeline specifications. The minimum carbon content coefficient for natural gas would match that for pure methane, which equates to an energy content of 1,005 Btu per standard cubic foot. Gas compositions with higher or lower Btu content tend to have higher carbon emissions factors, because the "low" Btu gas has a higher content of inert gases (including carbon dioxide offset with more NGLs), while "high" Btu gas tends to have more NGLs.

Step 2. Define flared gas

Every year, a certain amount of natural gas is flared in the United States. There are several reasons that gas is flared:

- There may be no market for some batches of natural gas, the amount may be too small or too variable, or the quality might be too poor to justify treating the gas and transporting it to market (such is the case when gas contains large shares of carbon dioxide). All natural gas flared for these reasons is probably "rich" associated gas, with relatively high energy content, high NGL content, and a high carbon content.
- Gas treatment plants may flare substantial volumes of natural gas because of "process upsets," because the gas is "off spec," or possibly as part of an emissions control system. Gas flared at processing plants may be of variable quality.

Data on the energy content of flare gas, as reported by states to EIA, indicate an energy content of 1,130 Btu per standard cubic foot. Flare gas may have an even higher energy content than reported by EIA since rich associated gas can have energy contents as high as 1,300 to 1,400 Btu per cubic foot.

Step 3. Determine a relationship between carbon content and heat content

A relationship between carbon content and heat content may be used to develop a carbon content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (and therefore carbon contents) of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states. To demonstrate that these samples were representative of actual natural gas "as

³ A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas.

consumed" in the United States, their heat content was compared to that of the national average. For the most recent year, the average heat content of natural gas consumed in the United States was 1,025 Btu per cubic foot, varying by less than 1 percent (1,025 to 1,031 Btu per cubic foot) over the past 5 years. Meanwhile, the average heat content of the 6,743 samples was 1,027 Btu per cubic foot, and the median heat content was 1,031 Btu per cubic foot. Thus, the average heat content of the sample set falls well within the typical range of natural gas consumed in the United States, suggesting that these samples continue to be representative of natural gas "as consumed" in the United States. The average and median composition of these samples appears in Table 2-22.

Table 2-22: Composition of Natural Gas (Percent)

Compound	Average	Median
Methane	93.07	95.00
Ethane	3.21	2.79
Propane	0.59	0.48
Higher Hydrocarbons	0.32	0.30
Non-hydrocarbons	2.81	1.43
Higher Heating Value (Btu per cubic foot)	1,027	1,032

Source: Gas Technology Institute (1992)

Carbon contents were then calculated for a series of sub samples stratified by heat content. Carbon contents were developed for eight separate sub-samples based on heat content and are shown in Table 2-23.

Table 2-23: Carbon Content of Pipeline-Quality Natural Gas by Energy Content (Tg/QBtu)

Sample	Average Carbon Content
GRI Full Sample	14.51
Greater than 1,000 Btu	14.47
1,025 to 1,035 Btu	14.45
975 to 1,000 Btu	14.73
1,000 to 1,025 Btu	14.43
1,025 to 1,050 Btu	14.47
1,050 to 1,075 Btu	14.58
1,075 to 1,100 Btu	14.65
Greater than 1,100 Btu	14.92
Weighted National Average	14.47

Source: EIA (1994).

Step 4. Apply carbon content coefficients developed in Step 3 to pipeline natural gas

Because there is some regional variation in the energy content of natural gas consumed, a weighted national average carbon content was calculated using the average carbon contents for each sub-sample of gas that conformed with an individual state's typical cubic foot of natural gas. The result was a weighted national average of 14.47 Tg/QBtu. This was identical to the average carbon content of all samples with more than 1,000 Btu per cubic foot and the average carbon content for all samples with a heat content between 1,025 and 1,050 Btu per cubic foot. Because those samples with a heat content below 1,000 Btu had an unusually high carbon content coefficient attributable to large portions of carbon dioxide (not seen in the median sample), they were excluded so as not to bias the carbon content coefficient upwards by including them in the final sample used to select a carbon content.

Step 5. Apply carbon content coefficients developed in Step 3 to flare gas

Selecting a carbon content coefficient for flare gas was much more difficult than for pipeline natural gas because of the uncertainty of its composition and uncertainty of the combustion efficiency of the flare. Because EIA estimates the heat content of flare gas at 1,130 Btu per cubic foot, the average carbon content for samples with more than 1,100 Btu per cubic foot, 14.92 Tg/QBtu, was adopted as the coefficient for flare gas. It should be noted that the sample data set did not include any samples with more than 1,130 Btu per cubic foot.

Data Sources

Natural gas samples were obtained from the Gas Technology Institute (formerly Gas Research Institute) database (1992) as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*.

Average heat content of natural gas consumed in the United States was taken from Table A4 of EIA's *Monthly Energy Review* (2003a).

Data on the average heat content consumed, on a state-by-state basis, was obtained from the U.S. Department of Energy, U.S. Energy Information Administration, *State Energy Data 2000: Consumption*, (2003b). Available online at <www.eia.doe.gov/emeu/states/_use_multistate.html>.

Uncertainty

The assignment of carbon content coefficients for natural gas, and particularly for flare gas, requires more subjective judgment than the methodology used for coal. This subjective judgment may introduce additional uncertainty.

Figure 2-1 shows the relationship between the calculated carbon contents for each natural gas sample and its energy content. This figure illustrates the relatively restricted range of variation in both the energy content (which varies by about 6 percent from average) and the carbon emission coefficient of natural gas (which varies by about 5 percent). Thus, the knowledge that gas has been sold via pipeline to an end-use consumer allows its carbon emission coefficient to be predicted with an accuracy of ± 5.0 percent.

Figure 2-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database

Source: EIA (1994).

Natural gas suppliers may achieve the same energy contents with a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Thus, the plot reveals large variations in carbon content for a single Btu value. In fact, the variation in carbon content for a single Btu value may be nearly as great as the variation for the whole sample. As a result, while energy content has some predictive value, the specific energy content does not substantially improve the accuracy of an estimated carbon content coefficient beyond the ± 5.0 percent offered with the knowledge that it is of pipeline-quality.

The plot of carbon content also reveals other interesting anomalies. Samples with the lowest emissions coefficients tend to have energy contents of about 1,000 Btu per cubic foot. They are composed of almost pure methane. Samples with a greater proportion of NGLs (e.g., ethane, propane, and butane) tend to have energy contents greater than 1,000 Btu per cubic foot, along with higher emissions coefficients. Samples with a greater proportion of inert gases tend to have lower energy content, but they usually contain carbon dioxide as one of the inert gases and, consequently, also tend to have higher emission coefficients (see left side of Figure 2-1).

For the full sample (N=6,743), the average carbon content of a cubic foot of gas was 14.51 Tg/QBtu (see Table 2-23). However, this average was raised by both the samples with less than 1,000 Btu per cubic foot that contain large amounts of inert carbon dioxide and those samples with more than 1,050 Btu per cubic foot that contain an unusually large amount of NGLs. Because typical gas consumed in the United States does not contain such a large amount of carbon dioxide or natural gas liquids, a weighted national average of 14.47 Tg/QBtu that represents fuels more typically consumed is used.⁴

Petroleum

There are four critical determinants of the carbon content coefficient for a petroleum-based fuel:

- The density of the fuel (e.g., the weight in kilograms of one barrel of fuel);
- The fraction by mass of the product that consists of hydrocarbons, and the fraction of non-hydrocarbon impurities;
- The specific types of ‘families’ of hydrocarbons that make up the hydrocarbon portion of the fuel; and
- The heat content of the fuel.

$$C_{\text{fuel}} = (D_{\text{fuel}} * S_{\text{fuel}}) / E_{\text{fuel}}$$

Where:

C_{fuel} is the carbon content coefficient of the fuel;

D_{fuel} is the density of the fuel;

S_{fuel} is the share of the fuel that is carbon; and

E_{fuel} is the heat content of the fuel.

Petroleum products vary between 5.6 degrees API gravity (dense products such as asphalt and road oil) and 247 degrees (ethane).⁵ This is a range in density of 60 to 150 kilograms per barrel, or ± 50 percent. The variation in

⁴ The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

⁵ API gravity is an arbitrary scale expressing the gravity or density of liquid petroleum products, as established by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the compound. Light crude oils generally exceed 38 degrees API and heavy crude oils are all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity. API gravity

carbon content, however, is much smaller (± 5 to 7 percent): ethane is 80 percent carbon by weight, while petroleum coke is 90 to 92 percent carbon. The tightly bound range of carbon contents can be explained by basic petroleum chemistry.

Petroleum Chemistry

Crude oil and petroleum products are typically mixtures of several hundred distinct compounds, predominantly hydrocarbons. All hydrocarbons contain hydrogen and carbon in various proportions. When crude oil is distilled into petroleum products, it is sorted into fractions by the boiling temperature of these hundreds of organic compounds. Boiling temperature is strongly correlated with the number of carbon atoms in each molecule. Petroleum products consisting of relatively simple molecules and few carbon atoms have low boiling temperatures, while larger molecules with more carbon atoms have higher boiling temperatures.

Products that boil off at higher temperatures are usually more dense, which implies greater carbon content as well. Petroleum products with higher carbon contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower carbon contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and carbon and hydrogen content. Figure 2-2 compares carbon content coefficients calculated on the basis of the derived formula with actual carbon content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were drawn from the sources described below in the discussions of individual petroleum products.

Figure 2-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density

Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in Guthrie (1960). Carbon content factors from other petroleum products are drawn from sources described below. Relationship between density and emission factors based on the relationship between density and energy content in DOC (1929), and relationship between energy content and fuel composition in Ringen et al. (1979).

The derived empirical relationship between carbon content per unit heat and density is based on the types of hydrocarbons most frequently encountered. Actual petroleum fuels can vary from this relationship due to non-hydrocarbon impurities and variations in molecular structure among classes of hydrocarbons. In the absence of more exact information, this empirical relationship offers a good indication of carbon content.

Non-hydrocarbon Impurities

Most fuels contain a certain share of non-hydrocarbon material. This is also primarily true of crude oils and fuel oils. The most common impurity is sulfur, which typically accounts for between 0.5 and 4 percent of the mass of most crude oils, and can form an even higher percentage of heavy fuel oils. Some crude oils and fuel oils also contain appreciable quantities of oxygen and nitrogen, typically in the form of asphaltenes or various acids. The nitrogen and oxygen content of crude oils can range from near zero to a few percent by weight. Lighter petroleum products have much lower levels of impurities, because the refining process tends to concentrate all of the non-hydrocarbons in the residual oil fraction. Light products usually contain less than 0.5 percent non-hydrocarbons by mass. Thus, the carbon content of heavy fuel oils can often be several percent lower than that of lighter fuels, due entirely to the presence of non-hydrocarbons.

can be calculated with the following formula: $\text{API Gravity} = (141.5/\text{Specific Gravity}) - 131.5$. Specific gravity is the density of a material relative to that of water. At standard temperature and pressure, there are 62.36 pounds of water per cubic foot, or 8.337 pounds water per gallon.

Variations in Hydrocarbon Classes

Hydrocarbons can be divided into five general categories, each with a distinctive relationship between density and carbon content and physical properties. Refiners tend to control the mix of hydrocarbon types in particular products in order to give petroleum products distinct properties. The main classes of hydrocarbons are described below.

Paraffins. Paraffins are the most common constituent of crude oil, usually comprising 60 percent by mass. Paraffins are straight-chain hydrocarbons with the general formula C_nH_{2n+2} . Paraffins include ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and octane (C_8H_{18}). As the chemical formula suggests, the carbon content of the paraffins increases with their carbon number: ethane is 80 percent carbon by weight, octane 84 percent. As the size of paraffin molecules increases, the carbon content approaches the limiting value of 85.7 percent asymptotically (see Figure 2-3).

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the carbon molecules form ring structures rather than straight chains, and consequently require two fewer hydrogen molecules than paraffins. Cycloparaffins always have the general formula C_nH_{2n} and are 85.7 percent carbon by mass, regardless of molecular size.

Olefins. Olefins are a reactive and unstable form of paraffin: a straight chain with the two hydrogen atoms at each end of the chain missing. They are never found in crude oil but are created in moderate quantities by the refining process. Thus, gasoline, for example, may contain 2 percent olefins. They also have the general formula C_nH_{2n} , and hence are also always 85.7 percent carbon by weight. Propylene (C_3H_6), a common intermediate petrochemical product, is an olefin.

Aromatics. Aromatics are very reactive hydrocarbons that are relatively uncommon in crude oil (10 percent or less). Light aromatics increase the octane level in gasoline, and consequently are deliberately created by steam reforming of naphtha. Aromatics also take the form of ring structures with some double bonds between carbon atoms. The most common aromatics are benzene (C_6H_6), toluene (C_7H_8), and xylene (C_8H_{10}). The general formula for aromatics is C_nH_{2n-6} . Benzene is 92 percent carbon by mass, while xylene is 90.6 percent carbon by mass. Unlike the other hydrocarbon families, the carbon content of aromatics declines asymptotically toward 85.7 percent with increasing carbon number and density. (See Figure 2-3)

Polynuclear Aromatics. Polynuclear aromatics are large molecules with a multiple ring structure and few hydrogen atoms, such as naphthalene ($C_{10}H_8$ and 94.4 percent carbon by mass) and anthracene ($C_{14}H_{10}$ and 97.7 percent carbon). They are relatively rare but do appear in heavier petroleum products.

Figure 2-3 illustrates the share of carbon by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules are generally used as lubricants, waxes, and residual fuel oil.

Figure 2-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number

Source: Hunt (1979).

If one knows nothing about the composition of a particular petroleum product, assuming that it is 85.7 percent carbon by mass is not an unreasonable first approximation. Since denser products have higher carbon numbers, this guess would be most likely to be correct for crude oils and fuel oils. The carbon content of lighter products is more affected by the shares of paraffins and aromatics in the blend.

Energy Content of Petroleum Products

The exact energy content (gross heat of combustion) of petroleum products is not generally known. EIA estimates energy consumption in Btu on the basis of a set of industry-standard conversion factors. These conversion factors are generally accurate to within 3 to 5 percent.

Individual Petroleum Products

The United States maintains data on the consumption of more than 20 separate petroleum products and product categories. The carbon contents, heat contents, and density for each product are provided below in Table 2-24. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table 2-24: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2002 Carbon Content (Tg/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.34	5.253	59.6	86.60
LPG	16.99	a	a	a
Jet Fuel	19.33	5.670	42.0	86.30
Distillate Fuel	19.95	5.825	35.5	86.34
Residual Fuel	21.49	6.287	11.0	85.68
Asphalt and Road Oil	20.62	6.636	5.6	83.47
Lubricants	20.24	6.065	25.6	85.80
Petrochemical Feedstocks	19.37	5.248 ^b	67.1 ^b	84.11 ^b
Aviation Gas	18.87	5.048	69.0	85.00
Kerosene	19.72	5.670	41.4	86.01
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.86	5.248	51.2	84.76
Petroleum Waxes	19.81	5.537	43.3	85.29
Still Gas	17.51	6.000	-	-
Crude Oil	20.23	5.800	30.5	85.49
Unfinished Oils	20.23	5.825	30.5	85.49
Miscellaneous Products	20.23	5.796	30.5	85.49
Pentanes Plus	18.24	4.620	81.7	83.70
Natural Gasoline	18.24	4.620	81.7	83.70

^a LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and carbon content, see Table 2-27.

^b Parameters presented are for naphthas with a boiling temperature less than 400 degrees Fahrenheit. Petrochemical feedstocks with higher boiling points are assumed to have the same characteristics as distillate fuel.

- No sample data available

Sources: EIA (1994), EIA (2003), and SAIC (2002).

Motor Gasoline and Motor Gasoline Blending Components

Motor gasoline is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines.⁶ "Motor Gasoline" includes conventional gasoline; all types of oxygenated gasoline, including gasohol; and reformulated gasoline; but excludes aviation gasoline.

Gasoline is the most widely used petroleum product in the United States, and its combustion accounts for nearly 20 percent of all U.S. carbon dioxide emissions. EIA collects consumption data (i.e., "petroleum products supplied" by wholesalers) for several types of gasoline: leaded regular, unleaded regular, and unleaded high octane. The American Society for Testing and Materials (ASTM) standards permit a broad range of densities for gasoline, ranging from 50 to 70 degrees API gravity, or 111.52 to 112.65 kilograms per barrel, which implies a range of

⁶ Motor gasoline, as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C, is characterized as having a boiling range of 122 degrees to 158 degrees Fahrenheit at the 10-percent recovery point to 365 degrees to 374 degrees Fahrenheit at the 90-percent recovery point.

possible carbon and energy contents per barrel. Table 2-25 reflects changes in the density of gasoline over time and across grades of gasoline through 2002.

Table 2-25: Motor Gasoline Density, 1990 – 2002 (Degrees API)

Fuel Grade	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Winter Grade													
Low Octane	62.0	61.8	61.4	61.0	60.1	59.8	60.6	61.5	61.8	61.6	61.6	61.7	61.6
Mid Octane	60.8	60.4	60.2	59.9	59.4	59.1	59.9	60.7	61.2	61.3	61.2	61.2	61.2
High Octane	59.0	59.3	59.0	58.7	58.5	58.0	58.5	59.3	60.0	60.3	59.7	59.1	59.0
Summer Grade													
Low Octane	58.2	58.0	57.4	56.1	55.7	56.1	56.9	57.1	57.6	57.7	56.8	57.2	56.5
Mid Octane	57.4	57.1	56.4	55.5	54.8	55.6	56.2	56.6	56.7	57.4	58.0	58.0	58.0
High Octane	55.5	55.7	55.6	54.4	53.8	55.1	55.3	56.4	55.7	57.4	55.8	55.5	55.7

Source: National Institute of Petroleum and Energy Research (1990 through 2002).

The density of motor gasoline increased across all grades through 1994, partly as a result of the leaded gasoline phase-out. In order to maintain the “anti-knock” quality and octane ratings of gasoline in the absence of lead, the portion of aromatic hydrocarbons used in gasoline increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to carbon than other hydrocarbons typically found in gasoline, and therefore increase fuel density.

The trend in gasoline density was reversed beginning in 1996 with the development of fuel additives that raised oxygen content. In 1995, a requirement for reformulated gasoline in non-attainment areas implemented under the Clean Air Act Amendments further changed the composition of gasoline consumed in the United States. In reformulated gasoline, methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME) are often added to standard gasoline to boost its oxygen content. The increased oxygen reduces the emissions of carbon monoxide and unburned hydrocarbons. These oxygen-rich blending components are also much lower in carbon than standard gasoline. The average gallon of reformulated gasoline consumed in 2001 contained 8 percent MTBE and 0.5 percent TAME. The characteristics of reformulated fuel additives appear in Table 2-26.

Table 2-26: Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees API)	Carbon Share (Percent)	Carbon Content (Tg/QBtu)
MTBE	59.1	68.2	16.92
ETBE	59.1	70.5	17.07
TAME	52.8	70.5	17.00

Source: API (1988).

Methodology

Step 1. Disaggregate U.S. gasoline consumption by grade and type

U.S. gasoline consumption was divided by product grade and season for both standard gasoline and reformulated gasoline.

Step 2. Develop carbon content coefficients for each grade and type

Carbon content coefficients for each grade and type are derived from three parameters: gasoline density, share of the gasoline mixture that is carbon; and the energy content of a gallon of gasoline. Carbon content coefficients for reformulated fuels were calculated by applying the carbon content coefficient for the fuel additives listed in Table 2-26 to the increased share of reformulated gasoline represented by these additives (standard gasoline contains small amounts of MTBE and TAME) and weighting the gasoline carbon content accordingly.

Step 3. Weight overall gasoline carbon content coefficient for consumption of each grade and type

The carbon content for each grade and type of fuel is multiplied by the share of overall consumption represented by the grade and fuel type. Individual coefficients are then summed and totaled to yield an overall carbon content coefficient.

Data Sources

Data for the density of motor gasoline was obtained from the National Institute for Petroleum and Energy Research, *Motor Gasolines, Summer* and *Motor Gasolines, Winter* (1990 through 2002).

Data on the characteristics of reformulated gasoline was taken from the American Petroleum Institute, *Alcohols and Ethers: A Technical Assessment of Their Applications as Fuels and Fuel Components*, API 4261 (1988).

Data on the carbon content of motor gasoline was obtained from the following:

- Mark DeLuchi, Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Volume 2, ANL/ESD/TM-22, Vol. 2 (November 1993), Appendix C, pp. C-1 to C-8.
- Ultimate analysis of one sample of shale-oil derived gasoline from Applied Systems Corp., Compilation of Oil Shale Test Results (April 1976), p. 3-2.
- Ultimate analysis of samples of three varieties of gasoline from C.C. Ward, "Petroleum and Other liquid Fuels," in Marks' Standard Handbook for Mechanical Engineers (1978), pp. 7-14.
- Ultimate analysis of one sample of gasoline from J.W. Rose and J.R. Cooper, Technical Data on Fuel, The British National Committee, World Energy Conference, London, England (1977).

Standard heat contents for motor gasoline of 5.253 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline were adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

There are two primary contributors to the uncertainty of carbon content coefficients for motor gasoline. The first is the small number of motor gasoline samples and ultimate analyses from Deluchi et al. However, as demonstrated above in Figure 2-3, the amount of variation in carbon content of gasoline is restricted by the compounds in the fuel to ± 4 percent.

The second primary contributor to uncertainty is the assumed heat content. The heat contents are industry standards established many years ago. The heat contents are standard conversion factors used by EIA to convert volumetric energy data to energy units. Because the heat contents of fuels change over time, without necessarily and directly altering their volume, the conversion of known volumetric data to energy units may introduce bias. Thus, a more precise approach to estimating emissions factors would be to calculate carbon content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. carbon content coefficients with those of other nations.

The changes in density of motor gasoline over the last decade suggest that the heat content of the fuels is also changing. However, that change within any season grade has been less than 1 percent over the decade. Of greater concern is the use of a standardized heat content across grades, which show a variation in density of ± 1.5 percent.

Jet Fuel

Jet fuel is a refined petroleum product used in jet aircraft engines. There are two classes of jet fuel used in the United States: "naphtha-based" jet fuels and "kerosene-based" jet fuels. In 1989, 13 percent of U.S. consumption was naphtha-based fuel, with the remainder kerosene-based jet fuel. In 1993, the U.S. Department of Defense began a conversion from naphtha-based JP-4 jet fuel to kerosene-based jet fuel, because of the possibility of increased demand for reformulated motor gasoline limiting refinery production of naphtha-based jet fuel. By 1996, naphtha-based jet fuel represented less than one-half of one percent of all jet fuel consumption. The carbon content coefficient for jet fuel used in this report represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients.

Methodology

Step 1. Estimate the carbon content for naphtha-based jet fuels

Because naphtha-based jet fuels are used on a limited basis in the United States, sample data on its characteristics are limited. The density of naphtha-based jet fuel (49 degrees) was estimated as the central point of

the acceptable API gravity range published by ASTM. The heat content of the fuel was assumed to be 5.355 MMBtu per barrel based on EIA industry standards. The carbon fraction was derived from an estimated hydrogen content of 14.1 percent (Martel and Angello 1977), and an estimated content of sulfur and other non-hydrocarbons of 0.1 percent.

Step 2. Estimate the carbon content for kerosene-based jet fuels

The density and carbon share of kerosene-based jet fuels was based on the average composition of 39 fuel samples taken by Boeing Corporation (the leading U.S. commercial airline manufacturer) in 1989. The EIA's standard heat content of 5.670 MMBtu per barrel was adopted for kerosene-based jet fuel.

Step 3. Weight the overall jet fuel carbon content coefficient for consumption of each type of fuel

The carbon content for each jet fuel type is multiplied by the share of overall consumption of that fuel type. Individual coefficients are then summed and totaled to yield an overall carbon content coefficient

Data Sources

Data on the carbon content of naphtha-based jet fuel was taken from C.R. Martel and L.C. Angello, "Hydrogen Content as a Measure of the Combustion Performance of Hydrocarbon Fuels," in *Current Research in Petroleum Fuels*, Volume I (1977), p. 116.

Data on the density of naphtha-based jet fuel was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985), p. 60.

Standard heat contents for kerosene- and naphtha- based jet fuels were adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Data on the carbon content and density of kerosene-based jet fuel was taken from O.J. Hadaller and A.M. Mommenty, *The Characteristics of Future Fuels*, Part 1, "Conventional Heat Fuels" (September 1990), pp. 46-50.

Uncertainty

Variability in jet fuel is relatively small with the average carbon share of kerosene-based jet fuel varying by less than ± 1 percent and the density varying by ± 1 percent. This is because the ratio of fuel mass to useful energy must be tightly bounded to maximize safety and range. There is more uncertainty associated with the density and carbon share of naphtha-based jet fuel because sample data were unavailable and default values were used. This uncertainty has only a small impact on the overall uncertainty of the carbon content coefficient for jet fuels, however, because naphtha-based jet fuel represents a small and declining share of total jet fuel consumption in the United States.

Distillate Fuel

Distillate fuel is a general classification for diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. No. 1, No. 2, and No. 4 fuel oils are also used for space heating and electric power generation.

Methodology

For the purposes of this report, the carbon content of No. 2 fuel oil is assumed to typify the carbon content of distillate fuel generally. The carbon share in No. 2 fuel oil was estimated based on the average of 11 ultimate analyses. This carbon share was combined with EIA's standard heat content of 5.825 MMBtu per barrel and the density of distillate assumed to be 35.5 degrees API, in accord with its heat content.

Data Sources

Data on the carbon contents and density was derived from four samples from C. T. Hare and R.L. Bradow, "Characterization of Heavy-Duty Diesel Gaseous and Particulate Emissions, and the Effects of Fuel Composition," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

Three samples from E.F. Funkenbush, D.G. Leddy, and J.H. Johnson, "The Organization of the Soluble Organic Fraction of Diesel Particulate Matter," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

One sample from R.L. Mason, "Developing Prediction Equations for Fuels and Lubricants," SAE Paper 811218, p.34 (1981).

One sample from C.T. Hare, K.J. Springer, and R.L. Bradow, "Fuel and Additive Effects on Diesel Particulate- Development and Demonstration of Methodology," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 179.

One Sample from F. Black and L. High, "Methodology for Determining Particulate and Gaseous Diesel Emissions," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

A standard heat content was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

The primary source of uncertainty for the estimated carbon content of distillate fuel is the selection of No.2 fuel oil as the typical distillate fuel. No.2 fuel oil is generally consumed for home heating. No.1 fuel oil is generally less dense and if it is consumed in large portions for mobile sources, the carbon content estimated for this report is likely to be too high. The five No.1 fuel oil samples obtained by EIA contained an average of 86.01 percent carbon compared to the 86.34 percent contained in samples of No.2 fuel oil. A carbon content coefficient based on No.1 fuel oil would equal 19.72 Tg/QBtu rather than the 19.95 Tg/QBtu for No. 2 fuel oil. There is also small uncertainty in the share of carbon based on the limited sample size of ± 1 percent.

Residual Fuel

Residual fuel is a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. Residual fuel conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

In the United States, electric utilities purchase about a third of the residual oil consumed. A somewhat larger share is used for vessel bunkering, and the balance is used in the commercial and industrial sectors. The residual oil (defined as No.6 fuel oil) consumed by electric utilities has an energy content of 6.287 MMBtu per barrel and an average sulfur content of 1 percent (EIA 2001a). This implies a density of about 17 degrees API.

Methodology

For this report, residual fuel was defined as No.6 fuel oil. The National Institute of Petroleum and Energy Research, Fuel Oil Survey shows an average density for fuel oil of 11.3 API gravity and anecdotal evidence suggests that marine residual fuel is also very dense, with typical gravity of 10.5 to 11.5 degrees API (EIA 1993). Because the largest share of fuel oil consumption is for marine vessels, a density of 11 degrees API was adopted when developing the carbon content coefficient for this report. An average share of carbon in residual fuel of 85.67 percent by mass was used based on ultimate analyses of a dozen samples.

Data Sources

Data on carbon content was derived from three samples of residual fuel from the Middle East and one sample from Texas. These data were found in F. Mosby, G.B. Hoekstra, T.A. Kleinhenz, and J.M. Sokra, "Pilot Plant Proves Resid Process," in *Chemistry of Petroleum Processing and Extraction* (1976), p.227.

Three samples of heavy fuel oils from J.P. Longwell, "Interface Between Fuels and Combustion," in *Fossil Fuel Combustion: A Sourcebook* (1991).

Three samples of heavy fuel oils from C.C. Ward, "Petroleum and Other Liquid Fuels," in *Marks' Standard Handbook for Mechanical Engineers* (1978), pp. 7-14.

Two samples of heavy fuel oils from, D.A. Vorum, "Fuel and Synthesis Gases from Gaseous and Liquid Hydrocarbons," in American Gas Association, *Gas Engineer's Handbook* (1974), p. 3/71.

One sample of heavy fuel oil from W. Rose and J.R. Cooper, *Technical Data on Fuel*, The British National Committee, World Energy Conference, London, England (1977).

Density of residual fuel consumed for electric power generation was obtained from EIA's *Cost and Quality of Fuels*, (2001a). Available online at <www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html>.

Density of residual fuel consumed in marine vessels from EIA's Petroleum Supply Division, *Btu Tax on Finished Petroleum Products* (1993) and National Institute for Petroleum and Energy Research's *Fuel Oil Surveys* (1992).

A standard heat content was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

The largest source of uncertainty for estimating the carbon content of residual fuel centers on the estimates of density, which differ from power generation to marine vessel fuels. The difference between the density implied by the energy content of utility fuels and the density observed in the NIPER surveys is probably due to nonsulfur impurities, which reduce the energy content without greatly affecting the density of the product. Impurities of several percent are commonly observed in residual oil. The presence of these impurities also affects the share of the fuel that is carbon. Overall, the uncertainty associated with the carbon content of residual fuel is probably ± 1 percent.

Liquefied Petroleum Gases (LPG)

EIA identifies four categories of paraffinic hydrocarbons as LPG: ethane, propane, isobutane, and n-butane. Because each of these compounds is a pure paraffinic hydrocarbon, their carbon shares are easily derived by taking into account the atomic weight of carbon (12) and the atomic weight of hydrogen (1). Thus, for example, the carbon share of propane, C₃H₈, is 81.8 percent. The densities and heat content of the compounds are also well known allowing carbon content coefficients to be calculated directly. Table 2-27 summarizes the physical characteristic of LPG.

Table 2-27: Physical Characteristics of Liquefied Petroleum Gases

Compound	Chemical Formula	Density (Barrels Per Metric Ton)	Carbon Content (Percent)	Energy Content (MMBtu/Barrel)	Carbon Content Coefficient (Tg/QBtu)
Ethane	C ₂ H ₆	16.88	80.0	2.916	16.25
Propane	C ₃ H ₈	12.44	81.8	3.824	17.20
Isobutane	C ₄ H ₁₀	11.20	82.8	4.162	17.75
n-butane	C ₄ H ₁₀	10.79	82.8	4.328	17.72

Source: Guthrie (1960).

Methodology

Step 1. Assign carbon content coefficients to each pure paraffinic compound

Based on their known physical characteristics, a carbon content coefficient is assigned to each compound contained in the U.S. energy statistics category, Liquefied Petroleum Gases.

Step 2. Weight individual LPG coefficients for share of fuel use consumption

A carbon content coefficient for LPG used as fuel is developed based on the consumption mix of the individual compound reported in U.S. energy statistics.

Step 3. Weight individual LPG coefficients for share of non-fuel use consumption

The mix of LPG consumed for non-fuel use differs significantly from the mix of LPG that is combusted. While the majority of LPG consumed for fuel use is propane, ethane is the largest component of LPG used for non-

fuel applications. A carbon content coefficient for LPG used for non-fuel applications is developed based on the consumption mix of the individual compound reported in U.S. energy statistics.

Step 4. Weight the carbon content coefficients for fuel use and non-fuel use by their respective shares of consumption

The changing shares of LPG fuel use and non-fuel use consumption appear below in Table 2-28.

Table 2-28: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2002 (Tg/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Consumption (Quads Fuel Use)													
Ethane	0.03	0.02	0.03	0.02	0.02	0.02	0.03	0.05	0.00	0.00	0.00	0.00	0.00
Propane	0.79	0.79	0.84	0.86	0.86	0.86	0.95	0.92	0.80	0.97	1.06	0.99	1.08
Butane	0.08	0.05	0.07	0.06	0.07	0.05	0.04	0.05	0.04	0.11	0.14	0.10	0.09
Total	0.90	0.85	0.94	0.94	0.96	0.93	1.02	1.03	0.84	1.09	1.20	1.09	1.17
Carbon Content	17.21	7.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.26	17.25	17.24
Consumption (Quads non-Fuel Use)													
Ethane	0.55	0.62	0.62	0.65	0.65	0.68	0.74	0.71	0.73	0.82	0.87	0.78	0.82
Propane	0.53	0.59	0.61	0.55	0.65	0.67	0.65	0.71	0.77	0.77	0.67	0.61	0.67
Butane	0.13	0.17	0.16	0.15	0.25	0.24	0.26	0.25	0.24	0.22	0.21	0.23	0.21
Total	1.20	1.38	1.39	1.35	1.55	1.59	1.65	1.67	1.74	1.82	1.75	1.62	1.69
Carbon Content	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.79	16.82	16.81
Weighted Carbon Content	16.99	16.98	16.99	16.97	17.01	17.00	16.99	16.99	16.99	16.99	16.99	16.99	16.99

Sources: Fuel use of LPG based on data from EIA (1995 through 2003) and API (1990 through 2001). Non-fuel use of LPG from API (1990 through 2002). Carbon contents from EIA (2003).

Data Sources

Data on carbon share, density, and heat content of LPG was obtained from V.B. Guthrie (ed.), *Characteristics of Compounds*, Petroleum Products Handbook, (1960), p.3-3.

Data on LPG consumption was based on data obtained from the American Petroleum Institute, Natural Gas Liquids and Liquefied Refinery Gas Survey (1990 through 2002) and from the U.S. Department of Energy, Energy Information Administration, *Petroleum Supply Annual* (1990 through 2003), which is available online at <www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>.

Non-fuel use of LPG was obtained from the American Petroleum Institute, Natural Gas Liquids and Liquefied Refinery Gas Survey (1990 through 2002).

Uncertainty

Because LPG consists of pure paraffinic compounds whose density, heat content and carbon share are physical constants, there is limited uncertainty associated with the carbon content coefficient for this petroleum product. Any uncertainty is associated with the collection of consumption data and non-fuel data in U.S. energy statistics. This uncertainty is probably less than ± 3 percent.

Aviation Gasoline

Aviation gasoline is used in piston-powered airplane engines. It is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in aviation reciprocating engines. Fuel specifications are provided in ASTM Specification D 910 and Military Specification MIL-G-5572. Aviation gas is a relatively minor contributor to greenhouse gas emissions compared to other petroleum products, representing approximately 0.1 percent of all consumption.

The ASTM standards for boiling and freezing points in aviation gasoline effectively limit the aromatics content to a maximum of 25 percent (ASTM D910). Because weight is critical in the operation of an airplane, aviation gas must have as many Btu per pound (implying a lower density) as possible, given other requirements of piston engines such as high anti-knock quality.

Methodology

A carbon content coefficient for aviation gasoline was calculated on the basis of the EIA standard heat content of 5.048 MMBtu per barrel. This implies a density of approximately 69 degrees API gravity or 5.884 pounds per gallon. To estimate the share of carbon in the fuel, it was assumed that aviation gasoline is 87.5 percent iso-octane, 9.0 percent toluene, and 3.5 percent xylene. The maximum allowable sulfur content in aviation gasoline is 0.05 percent, and the maximum allowable lead content is 0.1 percent. These amounts were judged negligible and excluded for the purposes of this analysis. This yielded a carbon share of 85 percent and a carbon content coefficient of 18.87 Tg/QBtu.

Data Sources

Data sources include American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for aviation gas was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

The uncertainty associated with the carbon content coefficient for aviation gasoline is larger than that for other liquid petroleum products examined because no ultimate analyses of samples are available. Given the requirements for safe operation of piston-powered aircraft the composition of aviation gas is well bounded and the uncertainty of the carbon content coefficient is likely to be ± 5 percent.

Still Gas

Still gas, or refinery gas is composed of light hydrocarbon gases that are released as petroleum is processed in a refinery. The composition of still gas is highly variable, depending primarily on the nature of the refining process and secondarily on the composition of the product being processed. Petroleum refineries produce still gas from many different processes. Still gas can be used as a fuel or feedstock within the refinery, sold as a petrochemical feedstock, or purified and sold as pipeline-quality natural gas. In general, still gas tends to include large amounts of free hydrogen and methane, as well as smaller amounts of heavier hydrocarbons. Because different refinery operations result in different gaseous byproducts, it is difficult to determine what represents typical still gas.

Methodology

The EIA obtained data on four samples of still gas. Table 2-29 below shows the composition of those samples.

Table 2-29: Composition, Energy Content, and Carbon Content Coefficient for Four Samples of Still Gas

Sample	Hydrogen (%)	Methane (%)	Ethane (%)	Propane (%)	Btu Per Cubic Foot	Carbon Content (Tg/QBtu)
One	12.7	28.1	17.1	11.9	1,388	17.51
Two	34.7	20.5	20.5	6.7	1,143	14.33
Three	72.0	12.8	10.3	3.8	672	10.23
Four	17.0	31.0	16.2	2.4	1,100	15.99

Because gas streams with a large free hydrogen content are likely to be used as refinery or chemical feedstocks, EIA selected the carbon content coefficient from the sample with the lowest hydrogen content as the representative value for still gas.

Data Sources

One still gas sample from American Gas Association, *Gas Engineer's Handbook* (1974), pp. 3/71, 3.87.

Three still gas samples from C.R. Guerra, K. Kelton, and D.C. Nielsen, Natural Gas Supplementation with Refinery Gases and Hydrogen," in Institute of Gas Technology, *New Fuels and Advances in Combustion Technologies* (1979).

Uncertainty

Because the composition of still gas is highly heterogeneous, the carbon content coefficient for this product is highly uncertain, with an accuracy of ± 33 percent. The carbon content coefficient used for this report is probably at the high end of the plausible range.

Asphalt

Asphalt is used to pave roads. Because most of its carbon is retained in those roads, it is a small source of emissions. It is derived from a class of hydrocarbons called "asphaltenes," abundant in some crude oils but not in others. Asphaltenes have oxygen and nitrogen atoms bound into their molecular structure, so that they tend to have lower carbon contents than other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average carbon content of 83.5 percent. The EIA standard Btu content for asphalt of 6.636 MMBtu per barrel was assumed. The ASTM petroleum measurement tables show a density of 5.6 degrees API or 8.605 pounds per gallon for asphalt. Together, these variables generate carbon content coefficient of 20.62 Tg/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

The density of asphalt was determined by the American Society for Testing and Materials, in *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Uncertainty

The share of carbon in asphalt ranges from 79 to 88 percent by weight. Also present in the mixture are hydrogen and sulfur, with shares by weight ranging from seven to 13 percent for hydrogen, and from trace levels to eight percent for sulfur. Because carbon share and total heat content in asphalts do vary systematically, the overall carbon content coefficient is likely to be accurate to ± 5 percent.

Lubricants

Lubricants are substances used to reduce friction between bearing surfaces, or incorporated into processing materials used in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Lubricant consumption is dominated by motor oil for automobiles, but there is a large range of product compositions and end uses within this category.

Methodology

The ASTM Petroleum Measurement tables give the density of lubricants at 25.6 degrees API. Ultimate analysis of a single sample of motor oil yielded a carbon content of 85.8 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a carbon content coefficient of 20.24 Tg/QBtu.

Data Sources

A standard heat content was adopted from the EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

The density of asphalt was determined by the American Society for Testing and Materials in *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Uncertainty

Uncertainty in the estimated carbon content coefficient for lubricants is driven by the large range of product compositions and end uses in this category combined with an inability to establish the shares of the various products captured under this category in U.S. energy statistics. Because lubricants may be produced from either the distillate or residual fractions during refineries, the possible carbon content coefficients range from just under 20.0 Tg/QBtu to about 21.5 Tg/QBtu or an uncertainty band from -1 percent to $+6$ percent of the estimated value.

Petrochemical Feedstocks

U.S. energy statistics distinguish between two different kinds of petrochemical feedstocks: those with a boiling temperature below 400 degrees Fahrenheit, generally called "naphtha," and those with a boiling temperature 400 degrees Fahrenheit and above.

Methodology

The method for estimating the carbon content of petrochemical feedstocks includes three steps.

Step 1. Estimate the carbon content coefficient for naphtha

Because reformed naphtha is used to make motor gasoline (hydrogen is released to raise aromatics content and octane rating), "straight-run" naphtha is assumed to be used as a petrochemical feedstock. Ultimate analyses of five samples of naphtha were examined and showed an average carbon share of 84.11 percent and an average density of 67.1 degrees API gravity. The standard EIA heat content of 5.248 MMBtu per barrel is used to estimate a carbon content coefficient of 18.14 Tg/QBtu.

Step 2. Estimate the carbon content coefficient for petrochemical feedstocks with a boiling temperature 400 degrees Fahrenheit and above

The boiling temperature of this product places it into the "middle distillate" fraction in the refining process, and EIA estimates that these petrochemical feedstocks have the same heat content as distillate fuel. Thus, the carbon content coefficient of 19.95 Tg/Btu used for distillate fuel is also adopted for this portion of petrochemical feedstocks.

Step 3. Weight the carbon content coefficients for the two classes of petrochemical feedstock by consumption

The weighted average of the two carbon content coefficients for petroleum feedstocks equals 19.37 Tg/Btu.

Data Sources

Data on the carbon content and density of naphtha was taken from G.H. Unzelman, "A Sticky Point for Refiners: FCC Gasoline and the Complex Model," *Fuel Reformulation* (July/August 1992), p. 29.

A standard heat content for petrochemical feedstock was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who may be presumed to be a chemical company or a petrochemical unit co-located on the refinery grounds. This produces a considerable degree of uncertainty about the exact composition of petrochemical feedstocks. Since the carbon content coefficient for petrochemical feedstocks is a weighted average of the coefficients for naphtha and some class of middle distillates, the accurate coefficient is likely bounded by the two individual coefficients, suggesting an uncertainty of ± 6 percent.

Kerosene

A light petroleum distillate that is used in space heaters, cook stoves, and water heaters and is suitable for use as a light source when burned in wick-fed lamps, kerosene is drawn from the same petroleum fraction as jet fuel. Kerosene is generally comparable to No.1 fuel oil.

Methodology

The average density of 41.4 degrees API and average carbon share of 86.01 percent found in five ultimate analyses of No. 1 fuel oil samples were applied to a standard heat content of 5.670 MMBtu per barrel to yield a carbon content coefficient of 19.72 Tg/Btu.

Data Sources

A standard heat content was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

Uncertainty in the estimated carbon content for kerosene is driven by the selection of No. 1 fuel oil as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true carbon content coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true carbon content coefficient is likely to be about 1 percent higher.

Petroleum Coke

Petroleum coke is the solid residue by-product of the extensive processing of crude oil. It is a coal-like solid, usually with a carbon content greater than 90 percent, that is used as a boiler fuel and industrial raw material.

Methodology

Ultimate analyses of two samples of petroleum coke showed an average carbon share of 92.3 percent. The ASTM standard density of 9.543 pounds per gallon was adopted and the EIA standard energy content of 6.024 MMBtu per barrel assumed. Together, these factors produced an estimated carbon content coefficient of 27.85 Tg/QBtu.

Data Sources

Carbon content was derived from two samples from S. W. Martin, "Petroleum Coke," in Virgil Guthrie (ed.), *Petroleum Processing Handbook* (1960), pp. 14-15.

The density of petroleum coke was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for petroleum coke was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

The uncertainty associated with the estimated carbon content coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish carbon contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the carbon content coefficient upwards by as much as 6 percent.

Special Naphtha

Special naphtha is defined as a light petroleum product to be used for solvent applications, including commercial hexane and four classes of solvent: stoddard solvent, used in dry cleaning; high flash point solvent, used as an industrial paint because of its slow evaporative characteristics; odorless solvent, most often used for residential paints; and high solvency mineral spirits, used for architectural finishes. These products differ in both density and carbon percentage, requiring the development of multiple coefficients.

Methodology

The method for estimating the carbon content coefficient of special naphtha includes three steps.

Step 1. Estimate the carbon content coefficient for hexane

Hexane is a pure paraffin containing 6 carbon atoms and 14 hydrogen atoms. Thus, it is 83.7 percent carbon. Its density is 76.6 degrees API or 5.649 pounds per gallon and its derived carbon content coefficient is 17.17 Tg/QBtu.

Step 2. Estimate the carbon contents of non-hexane special naphthas

The hydrocarbon compounds in special naphthas are assumed to be either paraffinic or aromatic (see discussion above). The portion of aromatics in odorless solvents is estimated at less than 1 percent, Stoddard and high flash point solvents contain 15 percent aromatics and high solvency mineral spirits contain 30 percent aromatics (Boldt and Hall 1977). These assumptions, when combined with the relevant densities, yield the carbon content factors contained in Table 2-30 below.

Table 2-30: Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Content (Percent)	Carbon Content (Tg/Btu)
Odorless Solvent	1	55.0	84.51	19.41
Stoddard Solvent	15	47.9	84.44	20.11
High Flash Point	15	47.6	84.70	20.17
Mineral Spirits	30	43.6	85.83	20.99

Step 3. Develop weighted carbon content coefficient based on consumption of each special naphtha

EIA reports only a single consumption figure for special naphtha. The carbon contents of the five special naphthas are weighted according to the following formula: approximately 10 percent of all special naphtha consumed is hexane; the remaining 90 percent is assumed to be distributed evenly among the four other solvents. The resulting emissions coefficient for special naphthas is 19.86 Tg/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Density and aromatic contents were adopted from K. Boldt and B.R. Hall, *Significance of Tests for Petroleum Products*, American Society for Testing and Materials (1977), p. 30.

Uncertainty

The principal uncertainty associated with the estimated carbon content coefficient for special naphtha is the allocation of overall consumption across individual solvents. The overall uncertainty is bounded on the low end by the carbon content of hexane and on the upper end by the carbon content of high solvency mineral spirits. This implies an uncertainty band of -15 percent to + 6 percent.

Petroleum Waxes

The ASTM standards define petroleum wax as a product separated from petroleum that is solid or semi-solid at 77 degrees Fahrenheit (25 degrees Celsius). The two classes of petroleum wax are paraffin waxes and microcrystalline waxes. They differ in the number of carbon atoms and the type of hydrocarbon compounds. Microcrystalline waxes have longer carbon chains and more variation in their chemical bonds than paraffin waxes.

Methodology

The method for estimating the carbon content coefficient for petroleum waxes includes three steps.

Step 1. Estimate the carbon content of paraffin waxes

For the purposes of this analysis, paraffin waxes are assumed to be composed of 100 percent paraffinic compounds with a chain of 25 carbon atoms. The resulting carbon share for paraffinic wax is 85.23 percent and the density is estimated at 45 degrees API or 6.684 pounds per gallon.

Step 2. Estimate the carbon content of microcrystalline waxes

Microcrystalline waxes are assumed to consist of 50 percent paraffinic and 50 percent cycloparaffinic compounds with a chain of 40 carbon atoms, yielding a carbon share of 85.56 percent. The density of microcrystalline waxes is estimated at 36.7 degrees API, based on a sample of 10 microcrystalline waxes found in the *Petroleum Products Handbook*.

Step 3. Develop a carbon content coefficient for petroleum waxes by weighting the density and carbon content of paraffinic and microcrystalline waxes

A weighted average density and carbon content was calculated for petroleum waxes, assuming that wax consumption is 80 percent paraffin wax and 20 percent microcrystalline wax. The weighted average carbon content is 85.29 percent, and the weighted average density is 6.75 pounds per gallon. EIA's standard heat content for waxes is 5.537 MMBtu per barrel. These inputs yield a carbon content coefficient for petroleum waxes of 19.81 Tg/QBtu.

Data Sources

Density of paraffin wax was taken from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Density of microcrystalline waxes was derived from 10 samples found in V. Guthrie (ed.), *Petroleum Products Handbook* (1960).

A standard heat content for petroleum waxes was adopted from EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

Although there is considerable qualitative uncertainty associated with the allocation of petroleum waxes and microcrystalline waxes, the quantitative variation in the carbon contents for all waxes is limited to ± 1 percent because of the nearly uniform relationship between carbon and other elements in petroleum waxes broadly defined.

Crude Oil, Unfinished Oils, and Miscellaneous

U.S. energy statistics include several categories of petroleum products designed to ensure that reported refinery accounts "balance" and cover any "loopholes" in the taxonomy of petroleum products. These categories include crude oil, unfinished oils, and miscellaneous products. Crude oil is rarely consumed directly, miscellaneous products account for less than one percent of oil consumption and unfinished oils are a balancing item that may show negative consumption. For carbon accounting purposes, it was assumed that all these products have the same carbon content as crude oil.

Methodology

EIA reports on the average density and sulfur content of U.S. crude oil purchased by refineries. To develop a method of estimating carbon content based on this information, ultimate analyses of 182 crude oil samples were collected. Within the sample set, carbon content ranged from 82 to 88 percent carbon, but almost all samples fell between 84 percent and 86 percent carbon. The density and sulfur content of the crude oil data were regressed on the carbon content, producing the following equation:

$$\text{Percent Carbon} = 76.99 + (10.19 * \text{Specific Gravity}) + (-0.76 * \text{Sulfur Content})$$

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.⁷ When carbon content was adjusted to exclude sulfur, the R-squared value rose to 0.65. While sulfur is the most important nonhydrocarbon impurity, nitrogen and oxygen can also be significant, but they do not seem to be correlated with either density or sulfur content. Restating these results, density accounts for about 35 percent of the variation in carbon content, impurities account for about 30 percent of the variation, and the remaining 35 percent is accounted for by other factors, including (presumably) the degree to which aromatics and polynuclear aromatics are present in the crude oil. Applying this equation to the 2001 crude oil quality data (30.49 degrees API and 1.42 percent sulfur) produces an estimated carbon content of 85.81 percent. Applying the density and carbon content to the EIA standard energy content for crude oil of 5.800 MMBtu per barrel produced an emissions coefficient of 20.23 Tg/QBtu.

Data Sources

Carbon content was derived from 150 crude oil samples from U.S. National Research Council, *International Critical Tables of Numerical Data, Physics, Chemistry, and Technology* (1927).

A standard heat content for crude oil was adopted from the EIA's *Monthly Energy Review, July 2003 and Unpublished Supplemental Tables on Petroleum Product detail* (2003a).

Uncertainty

The uncertainty of the estimated carbon content for crude oil centers on the 35 percent of variation that cannot be explained by density and sulfur content. This variation is likely to alter the carbon content coefficient by ± 3 percent. Since unfinished oils and miscellaneous products are impossible to define, the uncertainty of applying a

⁷ R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

crude oil carbon content is likely to be bounded by the range of petroleum products described in this chapter at ± 10 percent.

Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels

Coal

The estimates of carbon content coefficients for coal were updated and revised in 2002. The methodology employed for these estimates was unchanged from previous years; however, the underlying coal data sample set was updated. Previously a set of 5,426 coal samples from the EIA Coal Analysis File was used to develop carbon content estimates. The results from that sample set appear below in Table 2-31. The EIA Coal Analysis File was originally developed by the U.S. Bureau of Mines and contained over 60,000 coal samples obtained through numerous coal seams throughout the United States. Many of the samples were collected starting in the 1940s and 1950s through the 1980s and analyzed in U.S. government laboratories. The updated sample set included 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989.

Table 2-31: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990-2002 [Tg/QBtu]

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Electric Power	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00
Coal Rank													
Anthracite	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26 ^p
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49	25.49	25.49 ^p
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48	26.48	26.48 ^p
Lignite	26.19	26.21	26.22	26.21	26.24	26.22	26.17	26.20	26.23	26.26	26.30	26.30	26.30 ^p

p (Preliminary)

Sources: Carbon content coefficients by consuming sector from EIA (2003). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2002).

Petroleum Products

Jet Fuel

Between 1994 and 1995, the carbon content coefficient for kerosene-based jet fuel was revised downward from 19.71 Tg/QBtu to 19.33 Tg/QBtu. This downward revision was the result of a shift in the sample set used from one collected between 1959 and 1972 and reported on by Martel and Angello in 1977 to one collected by Boeing in 1989 and published by Hadaller and Momenty in 1990. The downward revision was a result of a decrease in density, as well as slightly lower carbon shares than in the earlier samples. However, the assumed heat content is unchanged because it is based on an EIA standard and probably yields a downward bias in the revised carbon content coefficient.

Liquefied Petroleum Gases (LPG)

The carbon content coefficient of LPG is updated annually to reflect changes in the consumption mix of the underlying compounds: ethane; propane; isobutane; and normal butane. In 1994, EIA included pentanes plus—assumed to have the characteristics of hexane—in the mix of compounds broadly described as LPG. In 1995, EIA removed pentanes plus from this fuel category. Because pentanes plus is relatively rich in carbon per unit of energy, its removal from the consumption mix lowered the carbon content coefficient for LPG from 17.26 Tg/QBtu to 17.02 Tg/QBtu. In 1998, EIA began separating LPG consumption into two categories: energy use and non-fuel use and providing individual coefficients for each. Because LPG for fuel use typically contains higher proportions of propane than LPG for non-fuel use, the carbon content coefficient for fuel use is about 2 percent higher than the coefficient for non-fuel use.

Motor Gasoline

The carbon content coefficient for motor gasoline varies annually based on the density of and proportion of additives in a representative sample of motor gasoline examined each year. However, in 1997 EIA began incorporating the effects of the introduction of reformulated gasoline into its estimate of carbon content coefficients for motor gasoline. This change resulted in a downward step function in carbon content coefficients for gasoline of approximately 0.3 percent beginning in 1995.

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2.3. Methodology for Estimating Carbon Stored in Products from Non-Energy Uses of Fossil Fuels

Carbon storage associated with the non-energy use of fossil fuels was calculated by multiplying each fuel's potential emissions (i.e., each fuel's total carbon content) by a fuel-specific storage factor, as listed in Table 2-32. This Annex explains the methods and data sources employed in developing the storage factors for asphalt and road oil, lubricants, petrochemical feedstocks, liquefied petroleum gases (LPG), pentanes plus, and natural gas used for chemical manufacturing plant feedstocks (i.e., not used as fuel.) The storage factors for the remaining non-energy fuel uses are based on values reported by Marland and Rotty (1984) and recommended for use by IPCC (1997).

Table 2-32: Fuel Types and Percent of Carbon Stored for Non-Energy Uses

Fuel Type	Storage Factor (%)
Industrial Coking Coal ^a	75%
Natural Gas to Chemical Plants	-
Nitrogenous Fertilizers	0%
Other Uses ^b	67%
Asphalt & Road Oil	100%
Liquefied Petroleum Gas (LPG) ^b	67%
Lubricants	9%
Pentanes Plus ^b	67%
Petrochemical Feedstocks	-
Naphtha (b.p.<401° F) ^b	67%
Other Oil (b.p.>401° F) ^b	67%
Petroleum Coke ^c	50%
Special Naphtha	0%
Other	-
Distillate Fuel Oil	50%
Residual Fuel	50%
Waxes	100%
Miscellaneous Products	100%

- Not applicable

^a Includes processes for which specific coking coal consumption and emission factor data are not available. Consumption of coking coal for production of iron and steel is covered in the Industrial Processes chapter.

^b The storage factor listed is the value for 2002. As described in this annex, the factor varies over time.

^c Includes processes for which specific petroleum coke consumption and emission factor data are not available (e.g., carbon fibers and textiles, refractory, electric motor parts, brake parts, batteries). Consumption of petroleum coke for production of primary aluminum anodes, electric arc furnace anodes, titanium dioxide, and ferroalloys is covered in the Industrial Processes chapter.

The following sections describe the selected non-energy uses in greater detail, outlining the methods employed and data used in estimating each storage factor. Several of the fuel types tracked by EIA—petrochemical feedstocks, pentanes plus, LPG, and natural gas—are used in organic chemical synthesis and in other manufacturing processes. Because the methods and data used to analyze them overlap, they are handled as a group and are discussed first. Discussions of the storage factors for asphalt, road oil and lubricants follow.

Petrochemical Feedstocks, Pentanes Plus, Liquefied Petroleum Gases, and Natural Gas

Petrochemical feedstocks, pentanes plus, liquefied petroleum gases (LPG) and natural gas¹ are used in the manufacture of a wide variety of man-made chemicals and products. Plastics, rubber, synthetic fibers, solvents, paints, fertilizers, pharmaceuticals, and food additives are just a few of the derivatives of these fuel types. Chemically speaking, these fuels are diverse, ranging from simple natural gas (i.e., predominantly methane, CH₄) to heavier, more complex naphthas and other oils.²

The four fuel categories constituted approximately 216.7 Tg CO₂ Eq., or 56 percent, of the 388.7 Tg CO₂ Eq. of non-energy fuel consumption in 2002. Of this amount for the four fuels, 9.5 Tg CO₂ Eq. was exported, resulting in a net U.S. consumption of 207.2 Tg CO₂ Eq. in 2002. For 2002 the storage factor for the four fuel categories was 67 percent. In other words, of the net consumption, 67 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 33 percent was emitted to the atmosphere directly as CO₂ (e.g., through combustion of industrial byproducts) or indirectly as CO₂ precursors (e.g., through evaporative product use). The indirect emissions include a variety of organic gases such as volatile organic compounds (VOCs) and carbon monoxide (CO), which eventually oxidize into CO₂ in the atmosphere. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

An empirically determined storage factor was developed for the carbon consumed for non-energy end uses of petrochemical feedstocks, pentanes plus, LPG, and natural gas (henceforth referred to as feedstocks). The storage factor is equal to the ratio of carbon stored in the final products to total carbon content for the non-energy fossil fuel feedstocks used in industrial processes, after adjusting for net exports of feedstocks. One aggregate storage factor was calculated to represent all four fuel feedstock types. The feedstocks were grouped because of the overlap of their derivative products. Due to the many reaction pathways involved in producing petrochemical products (or wastes), it becomes extraordinarily complex to link individual products (or wastes) to their parent fuel feedstocks.

Import and export data for feedstocks were obtained from the Energy Information Administration (EIA) for the major categories of petrochemical feedstocks. EIA's *Petroleum Supply Annual* (EIA 2001c) publication tracks imports and exports of petrochemical feedstocks, including butanes, butylenes, ethane, ethylene, propane, propylene, LPG, and naphthas (i.e., most of the large volume primary chemicals produced by petroleum refineries). These imports and exports are already factored into the U.S. fuel consumption statistics. However, EIA does not track imports and exports of chemical intermediates and products produced by the chemical industry (e.g., xylenes, vinyl chloride, polypropylene resins), which were derived from the primary chemicals produced by the refineries. These products represent very large flows of carbon derived from fossil fuels (i.e., fossil carbon), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2002.

The approach to estimate imports and exports involves three steps:

- Step 1.* Identify commodities derived from petrochemical feedstocks, and calculate net import/export for each.
- Step 2.* Estimate the carbon content for each commodity.
- Step 3.* Sum the net carbon imports/exports across all commodities.

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and trade statistics published by the U.S. Bureau of the Census (BoC). NPRA provided a spreadsheet of the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-export data for periodic reports issued to NPRA's membership on trade issues. Additional feedstock commodities were identified by HTS code in the BoC data system and included in the net import/export analysis.

¹ Natural gas has two categories of non-energy consumption: for fertilizer and for other chemical syntheses. Only natural gas that is supplied to chemical plants for other uses is included here. Natural gas used for fertilizer is not included because it covered in the Industrial Processes chapter.

² Naphthas are compounds distilled from petroleum containing 4 to 12 carbon atoms per molecule and having a boiling point less than 401° F. Other oils are distillates containing 12 to 25 carbon atoms per molecule and having a boiling point greater than 401° F.

One of the difficulties in analyzing trade data is that a large portion of the outputs from the refining industry are fuels and fuel components, and it was difficult to segregate these from the outputs used for non-energy uses. The NPRA-supplied codes identify fuels and fuel components, thus providing a sound basis for isolating net imports/exports of petrochemical feedstocks. Although MTBE and related ether imports are included in the published NPRA data, these commodities are not included in the total net imports/exports calculated here, because it is assumed that they are fuel additives and do not contribute to domestic petrochemical feedstocks. Net exports of MTBE and related ethers *are* included in the totals, however, as these commodities are petrochemicals produced from fossil fuels for export, and deplete domestic petrochemical feedstocks. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, liquefied petroleum gases) are also not included in the totals, to avoid double counting.

The BoC trade statistics are publicly available³ and cover a complete time series from 1990 to 2001. These statistics include information on imports and exports of thousands of commodities. After collecting information on annual flows of the more than 100 commodities identified by NPRA, Step 2 involves calculating the carbon content for each commodity from its chemical formula. In cases where the imports and exports were expressed in units of volume, rather than mass, they were converted to mass based on the commodities' densities.

Step 3 involves summing the net carbon imports/exports across all commodities. The results of this step are shown in Table 2-33. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2002 period.

Table 2-33: Net Exports of Petrochemical Feedstocks, 1990 – 2002 (Tg CO₂ Eq)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002*
Net Exports	28.7	34.5	29.1	31.1	27.0	26.9	26.3	32.6	24.3	22.9	23.5	9.5	9.5

* Data for 2002 were not yet available, so 2002 was held constant at the 2001 value

After adjusting for imports and exports, the carbon budget is adjusted for the quantity of carbon that is used in the industrial processes sector of the GHG inventory. Fossil fuels used for non-energy purposes in industrial processes – and for which carbon emissions and storage have been characterized through mass balance calculations and/or emission factors that directly link the non-energy use fossil fuel raw material and the industrial process product – are not included in the non-energy use sector. These industrial processes (and their non-energy use fossil fuel raw materials) include iron and steel (coal coke), primary aluminum (petroleum coke), titanium oxide (petroleum coke), ferroalloys (petroleum coke), and ammonia and urea (natural gas).

For each year in the inventory, the total carbon content of non-energy uses was calculated by starting with the EIA estimate of non-energy use, and reducing it by the adjustment factor for net exports (see Table 2-33) to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored carbon or emissive carbon, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the carbon in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total carbon in the system was estimated by multiplying net domestic consumption for non-energy by the carbon content of each of the feedstocks (i.e., petrochemical feedstocks-naphtha, petrochemical feedstocks-other oils, LPG, pentanes plus, natural gas). Carbon content values for the fuel feedstocks are discussed in Annexes A and B.

Next, carbon pools and releases in a variety of industrial releases, energy recovery processes, and products were characterized. The carbon fate categories are plastics, energy recovery, synthetic rubber, synthetic fibers, organic solvents, carbon black, detergents and personal cleansers, industrial non-methane volatile organic compound (NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, and refinery wastewater discharges.⁴

³ See the U.S International Trade Commission (USITC) Trade Dataweb at <<http://dataweb.usitc.gov/>>.

⁴ For the most part, the releases covered by the U.S. Toxic Release Inventory (TRI) represent air emissions or water discharges associated with production facilities. Similarly, VOC emissions are generally associated with production facilities. These emissions could have been accounted for as part of the Waste chapter, but because they are not necessarily associated with waste management, they were included here. Toxic releases are not a “product” category, but they are referred to as such for ease of discussion.

The carbon in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the carbon-weighted average of storage across fuel types. As discussed later in the section on uncertainty, the sum of stored carbon and emitted carbon (i.e., the outputs of the system) generally exceeded total carbon consumption (the inputs to the system) for each year in the time series.⁵ To address this mass imbalance, the storage factor was calculated as carbon storage divided by total carbon outputs (rather than carbon storage divided by carbon inputs).

Note that the system boundaries for the storage factor do not encompass the entire life-cycle of fossil-based carbon consumed in the United States insofar as emissions of CO₂ from waste combustion are accounted for separately in the Inventory and are discussed in the Waste Combustion section of the Energy chapter.

The following sections provide details on the calculation steps, assumptions, and data sources employed in estimating and classifying the carbon in each product and waste shown in Table 2-34. Summing the carbon stored and dividing it by total carbon outputs yields the overall storage factor, as shown in the following equation for 2002:

$$\text{Overall Storage Factor} = \text{Carbon Stored} / (\text{Carbon Stored} + \text{Carbon Emitted}) = \\ 165.5 \text{ Tg CO}_2 \text{ Eq.} / (165.5 + 80.7) \text{ Tg CO}_2 \text{ Eq.} = 67 \%$$

Table 2-34: Carbon Stored and Emitted by Products from Petrochemical Feedstocks, Pentanes Plus, LPG, and Natural Gas in 2002 (Tg CO₂ Eq.)

Product/Waste Type	Carbon Stored	Carbon Emitted
Industrial Releases	0.1	8.1
<i>TRI Releases</i>	<i>0.1</i>	<i>1.0</i>
Industrial VOCs	-	4.0
<i>Non-combustion CO</i>	<i>-</i>	<i>1.3</i>
<i>Refinery wastewater</i>	<i>-</i>	<i>0.1</i>
<i>Hazardous Waste Incin.</i>	<i>-</i>	<i>1.8</i>
Energy Recovery	-	58.1
Products	165.3	14.6
<i>Plastics</i>	<i>130.8</i>	<i>-</i>
<i>Synthetic Rubber</i>	<i>16.4</i>	<i>-</i>
<i>Synthetic Fiber</i>	<i>11.7</i>	<i>-</i>
<i>Carbon Black</i>	<i>6.2</i>	<i>-</i>
<i>Pesticides</i>	<i>0.3</i>	<i>0.2</i>
<i>Soaps, shampoos, detergents</i>	<i>-</i>	<i>4.9</i>
<i>Solvent VOCs</i>	<i>-</i>	<i>9.5</i>
Unaccounted for*		-39.0
Total	165.5	80.7

- Not applicable

* Unaccounted for carbon was assumed to be emitted; however, negative values were not counted in the total emissions.

Note: Totals may not sum due to independent rounding.

The three categories of carbon accounted for in the table are industrial releases, energy recovery, and products. Each is discussed below.

Industrial Releases

Industrial releases include toxics reported through the Toxics Release Inventory, industrial emissions of volatile organic compounds (VOCs), carbon monoxide emissions (other than those related to fuel combustion), treatment of refinery wastewater, and hazardous waste incineration.

⁵ Overall, there was fairly close agreement between inputs and outputs; for the entire 1990 – 2002 time series, outputs exceeded inputs by 5 percent. The only year in which carbon inputs exceeded carbon outputs (i.e., the sum of carbon stored and carbon emitted) was 1994. For that year, the assumption was made that the “missing” carbon was lost through fates leading to emissions.

TRI Releases

Fossil-derived carbon is found in many toxic substances released by industrial facilities. The Toxics Release Inventory (TRI), maintained by EPA, tracks these releases by chemical and environmental release medium (i.e., land, air, or water) on a biennial basis (EPA 2000b). By examining the carbon contents and receiving media for the top 35 toxic chemicals released, which account for 90 percent of the total mass of chemicals, the quantity of carbon stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so carbon contents were assigned to each chemical based on molecular formula. The TRI also classifies releases by disposal location as either off-site or on-site. The on-site releases are further subdivided into air emissions, surface water discharges, underground injection, and releases to land; the latter is further broken down to disposal in a RCRA Subtitle C (i.e., hazardous waste) landfill or to “Other On-Site Land Disposal.”⁶ The carbon released in each disposal location is provided in Table 2-35.

Each on-site classification was assigned a storage factor. A one hundred percent storage factor was applied to disposition of carbon to underground injection and to disposal to RCRA-permitted landfills, while the other disposition categories were assumed to result in an ultimate fate of emission as CO₂ (i.e., a storage factor of zero was applied to these categories.) The release allocation is not reported for off-site releases; therefore, the approach was to develop a carbon-weighted average storage factor for the on-site carbon and apply it to the off-site releases.

For the remaining 10 percent of the TRI releases, the weights of all chemicals were added and an average carbon content value, based upon the top 35 chemicals’ carbon contents, was applied. The storage and emission allocation for the remaining 10 percent of the TRI releases was carried out in the same fashion as for the 35 major chemicals.

Data on TRI releases for the full 1990-2002 time series were not readily available. Since this category is small (less than 1 MMTC emitted and stored), the 1998 value was applied for the entire time series.

Table 2-35: 1998 TRI Releases by Disposal Location (Gg CO₂ Eq.)

Disposal Location	Carbon Stored	Carbon Emitted
Air Emissions	-	924.0
Surface Water Discharges	-	6.7
Underground Injection	89.4	-
RCRA Subtitle C Landfill Disposal	1.4	-
Other On-Site Land Releases	-	15.9
Off-site Releases	6.4	36.0
Total	97.2	982.6

- Not applicable

Note: Totals may not sum due to independent rounding.

Volatile Organic Compound Emissions from Industrial Processes and Solvent Evaporation Emissions

Data on annual non-methane volatile organic compound (NMVOC) emissions were obtained from National Air Quality and Emissions Trends Report data (EPA 2002a). The 1990-2000 Trends Report data include information on NMVOC emissions by end-use category; some of these fall into the heading of “industrial releases” in Table 2-34 above, and others are related to “product use”; for ease of discussion, both are covered here. The end-use categories that represent “Industrial NMVOC Emissions” include chemical and allied products, petroleum and related industries, metals processing, and other industrial processes. NMVOC emissions from solvent utilization (product use) were considered to be a result of non-energy use of petrochemical feedstocks. These categories were used to distinguish non-energy uses of the four fuel types from energy uses; other categories where VOCs could be emitted due to combustion of fossil fuels were excluded to avoid double counting.

Because solvent evaporation and industrial NMVOC emission data are provided in tons of total NMVOCs, assumptions were made concerning the average carbon content of the NMVOCs for each category of emissions.

⁶ Only the top 9 chemicals had their land releases separated into RCRA Landfills and Other Land Disposal. For the remaining chemicals, it was assumed that the ratio of disposal in these two categories was equal to the carbon-weighted average of the land disposal fate of the top 9 chemicals (i.e., 8 percent attributed to RCRA Landfills and 92 percent in the “Other” category).

The assumptions for calculating the carbon fraction of industrial and solvent utilization emissions were made separately and differ significantly. For industrial NMVOC emissions, the carbon content of 85 percent was assumed. This value was chosen to reflect the carbon content of an average volatile organic compound based on the list of the most abundant NMVOCs provided in the Trends Report. The list contains only pure hydrocarbons, including saturated alkanes (carbon contents ranging from 80 to 85 percent based upon carbon number), alkenes (carbon contents approximately 85.7 percent), and some aromatics (carbon contents approximately 90 percent, depending upon substitution).

An EPA solvent evaporation emissions dataset (Tooley 2001) was used to estimate the carbon content of solvent emissions. The dataset identifies solvent emissions by compound or compound category for six different solvent end-use categories: degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes. The percent carbon of each compound identified in the dataset was calculated based on the molecular formula of the individual compound (e.g., the carbon content of methylene chloride is 14 percent; the carbon content of toluene is 91 percent). For solvent emissions that are identified in the EPA dataset only by chemical category (e.g., butanediol derivatives) a single individual compound was selected to represent each category, and the carbon content of the category was estimated based on the carbon content of the representative compound. The overall carbon content of the solvent evaporation emissions for 1998, estimated to be 56 percent, is assumed to be constant across the entire time series.

The results of the industrial and solvent NMVOC emissions analysis are provided in Table 2-36 for the years 1990 through 2002. Data for solvent evaporation for 2002 have not been published, and therefore the entry for 2002 has been held constant at the value of the most recent available datum, that for the 2001 calendar year. Data for industrial NMVOC emissions for 2001 and 2002 have not been published, and therefore data for 2001 and 2002 have been held constant at the value for 2000.

Table 2-36: Industrial and Solvent NMVOC Emissions

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Industrial NMVOCs^a													
NMVOCs ('000 Short Tons)	1,769	1,865	1,886	1,916	1,902	1,878	1,359	1,391	1,400	1,359	1,399	1,399	1,399
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (Tg CO ₂ Eq.)	5.0	5.3	5.3	5.4	5.4	5.3	3.8	3.9	4.0	3.8	4.0	4.0	4.0
Solvent Evaporation^b													
Solvents ('000 Short Tons)	5,750	5,782	5,901	6,016	6,162	6,183	5,477	5,622	5,149	4,997	4,874	5,053	5,053
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (Tg CO ₂ Eq.)	10.8	10.8	11.0	11.3	11.5	11.6	10.3	10.5	9.6	9.4	9.1	9.5	9.5

^a Includes emissions from chemical and allied products, petroleum and related industries, and other industrial processes categories.

^b Includes solvent usage and solvent evaporation emissions from degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes.

Non-Combustion Carbon Monoxide Emissions

Carbon monoxide (CO) emissions data were also obtained from the National Air Quality and Emissions Trends Report (EPA 2000b). There are four categories of CO emissions in the report that are classified as process-related emissions not related to fuel combustion. These include chemical and allied products manufacturing, metals processing, petroleum and related industries, and other industrial processes. Some of these CO emissions are accounted for in the Industrial Processes section of this report, and are therefore not accounted for in this section. These include total carbon emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total carbon (CO and CO₂) emissions from oil and gas production and asphalt manufacturing are also accounted for elsewhere in this Inventory. Sustainably harvested biogenic emissions (e.g., pulp and paper process emissions) are also excluded from calculation of CO emissions in this section. Those CO emissions that are not accounted for elsewhere are considered to be byproducts of non-fuel use of feedstocks and are included in the calculation of the petrochemical feedstocks storage factor. Table 2-37 lists the industrial processes and CO emissions that remain after taking into account the exclusions listed above. Data for non-combustion CO

emissions for 2001 and 2002 have not been published, and therefore data for these years have been held constant at the value for 2000.

Table 2-37: Non-Combustion Carbon Monoxide Emissions^a

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Thousand short tons CO	781	765	800	830	779	790	864	892	886	881	897	897	897
Carbon Emitted (Tg CO ₂ Eq.)	1.1	1.1	1.1	1.2	1.1	1.1	1.2	1.3	1.3	1.3	1.3	1.3	1.3

^a Includes emissions from chemical and allied products, petroleum and related industries, metals processing, and other industrial processes categories.

Refinery Wastewater

Carbon flows associated with the treatment and discharge of refinery wastewater are included in the mass balance. To develop an estimate of annual emissions associated with the wastewater, it was assumed that the average concentration of Total Organic Carbon in refinery effluents was 10.5 mg/L, based on 1992 data reported in EPA's Permit Compliance System. It was also assumed that (a) the overall treatment efficiency (excluding recycling of oil back to the refinery) was 90 percent, (b) average flow is about 1 million gallons per day (3,800 m³/day), there are 192 operating refineries in the United States, (c) the majority of organic compounds in refinery wastewater are not covered by the TRI requirements (and thus there is no significant double-counting of releases with the TRI estimate), and (d) all of the carbon in the raw wastewater is destined for emission as CO₂. Based on these assumptions, annual emissions are roughly 0.1 Tg CO₂ Eq. Note that fugitive air emissions of methane from treatment of refinery wastewater are already accounted for in the inventory in the category of "Petroleum Systems," but other fugitive air emissions and discharges of wastewater to surface water or publicly owned treatment works are not included elsewhere in the inventory. More recent data on refinery effluents has not been found, and thus the entire time series has been assumed to have the same value as 1992.

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).⁷ Industrial wastes, such as rejected products, spent reagents, reaction by-products, and sludges from wastewater or air pollution control, are federally regulated as hazardous wastes if they are found to be ignitable, corrosive, reactive, or toxic according to standardized tests or studies conducted by the EPA.

Hazardous wastes must be treated prior to disposal according to the federal regulations established under the authority of RCRA. Combustion is one of the most common techniques for hazardous waste treatment, particularly for those wastes that are primarily organic in composition or contain primarily organic contaminants. Generally speaking, combustion devices fall into two categories: incinerators that burn waste solely for the purpose of waste management, and boilers and industrial furnaces (BIFs) that burn waste in part to recover energy from the waste. More than half of the hazardous waste combusted in the U.S. is burned in BIFs; these processes are included in the energy recovery calculations described below.

EPA's Office of Solid Waste requires biennial reporting of hazardous waste management activities, and these reports provide estimates of the amount of hazardous waste burned for incineration or energy recovery. EPA stores this information in its Biennial Reporting System (BRS) database (EPA 2000a). Combusted hazardous wastes are identified based on EPA-defined management system types M041 through M049 (incineration). Combusted quantities are grouped into four representative waste form categories based on the form codes reported in the BRS: aqueous liquids, organic liquids and sludges, organic solids, and inorganic solids. To relate hazardous waste quantities to carbon emissions, "fuel equivalent" factors were derived for hazardous waste by assuming that the hazardous wastes are simple mixtures of a common fuel, water, and noncombustible ash. For liquids and sludges, crude oil is used as the fuel equivalent and coal is used to represent solids.

Fuel equivalent factors were multiplied by the tons of waste incinerated to obtain the tons of fuel equivalent. Multiplying the tons of fuel equivalent by the carbon content factors (discussed in Annex A) yields tons of carbon emitted. Implied carbon content is calculated by dividing the tons of carbon emitted by the associated tons of waste incinerated.

⁷ [42 U.S.C. §6924, SDWA §3004]

Waste quantity data for hazardous wastes were obtained from EPA's BRS database for reporting years 1989, 1991, 1993, 1995, and 1997 (EPA 2000a). Values for years after 1997 were held constant at the 1997 level. Combusted waste quantities were obtained from Form GM (Generation and Management) for wastes burned on site and Form WR (Wastes Received) for waste received from off-site for combustion. For each of the waste types, assumptions were developed on average waste composition (see Table 2-38). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of carbon oxidized.

Table 2-38: Assumed Composition of Combusted Hazardous Waste by Weight (Percent)

Waste Type	Water	Noncombustibles	Fuel Equivalent
Aqueous Waste	90	5	5
Organic Liquids and Sludges	40	20	40
Organic Solids	20	40	40
Inorganic Solids	20	70	10

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1991, 1994, and 1998 (EIA 1994, 1997, 2001b). Some fraction of the fossil carbon exiting refineries and designated for use for feedstock purposes actually ends up being combusted for energy recovery (despite the designation of feedstocks as a "non-energy" use) because the chemical reactions in which fuel feedstocks are used are not 100 percent efficient. These chemical reactions may generate unreacted raw material feedstocks or generate byproducts that have a high energy content. The chemical industry and many downstream industries are energy-intensive and often have boilers or other energy recovery units on-site, and thus these unreacted feedstocks or byproducts are often combusted for energy recovery. Also, as noted above in the section on hazardous waste incineration, regulations provide a strong incentive—and in some cases require—burning of organic wastes generated from chemical production processes.

Information available from the MECS include data on the consumption for energy recovery of "other" fuels in the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. These "other" fuels include refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; and other uncharacterized fuels. Fuel use of petroleum coke is included separately in the fuel use data provided annually by EIA, and energy recovery of coke oven gas and blast furnace gas (i.e., byproducts of the iron and steel production process) is addressed in the Iron and Steel production section in the Industrial Processes chapter. Consumption of refinery still gas in the refinery sector is also included separately in the fuel use data from EIA. Consumption of net steam, assumed to be generated from fossil fuel combustion, is also included separately in the fuel use data from EIA. Therefore these categories of "other" fuels are addressed elsewhere in the inventory and not considered as part of the petrochemical feedstocks energy recovery analysis. The remaining categories of fuels, including waste gas; waste oils, tars, and related materials; and other uncharacterized fuels are assumed to be petrochemical feedstocks burned for energy recovery (see Table 2-40). The conversion factors listed in Annex A were used to convert the Btu values for each fuel feedstock to Tg CO₂. Petrochemical feedstocks combusted for energy recovery corresponded to 42.2 Tg CO₂ Eq. in 1991, 35.4 Tg CO₂ Eq. in 1994, and 58.1 Tg CO₂ Eq. in 1998. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994 and between 1994 and 1998 have been estimated by interpolation. The value for 1990 is assumed to be the same as the value for 1991, and values for years subsequent to 1998 are assumed to be the same as the value for 1998 (Table 2-39).

Table 2-39: Carbon Emitted from Fuels Burned for Energy Recovery (Tg CO₂ Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Emissions	42.2	42.2	40.0	37.7	35.4	41.1	46.8	52.4	58.1	58.1	58.1	58.1	58.1

Table 2-40: Summary of 1998 MECS Data for Other Fuels Used in Manufacturing/Energy Recovery (Trillion Btu)

Subsector and Industry	NAICS CODE	Waste Gas ^a	Waste Oils/Tars ^b	Refinery Still Gas ^c	Net Steam ^d	Other Fuels ^e
Printing and Related Support	323	0	1	0	0	1
Petroleum and Coal Products	324	0	1	1399	93	231
Chemicals	325	416	16	0	194	118
Plastics and Rubber Products	326	0	0	0	5	0
Nonmetallic Mineral Products	327	2	9	0	0	14
Primary Metals	331	2	2	0	17	5
Fabricated Metal Products	332	1	0	0	2	4
Machinery	333	0	1	0	1	2
Computer and Electronic Products	334	0	0	0	1	0
Electrical Equip., Appliances, Components	335	1	1	0	2	0
Transportation Equipment	336	1	2	0	7	19
Miscellaneous	337	0	0	0	0	2
Total (Trillion BTUs)		423	33	1399	323	395
Carbon Content (Tg/QBTU)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		0.99	0.99	0.99	0	0.99
Total Carbon (Tg)		7.60	0.67	24.25		7.58
Total Carbon (Tg) (exc still gas from refining)		7.60	0.67	0.00		7.58

^a Carbon content: Waste Gas is assumed to be same as naphtha <401 deg. F

^b Carbon content: Waste Oils/Tars is assumed to be same as asphalt/road oil

^c Refinery "still gas" fuel consumption is reported elsewhere in the inventory and is excluded from the total carbon content estimate

^d Net steam fuel consumption is reported elsewhere in the inventory and is excluded from the total carbon content estimate

^e Carbon content: "Other" is assumed to be the same as petrochemical feedstocks

Products

More carbon is found in products than in industrial releases or energy recovery. The principal types of products are plastics; synthetic rubber; synthetic fiber; carbon black; pesticides; soaps, detergents, and cleansers; and solvents. Solvent evaporation was discussed previously along with industrial releases of NMVOCs; the other product types are discussed below.

Plastics

Data on annual production of plastics were taken from the American Plastics Council (APC), as published in *Chemical & Engineering News* and on the APC and Society of Plastics Industry (SPI) websites, and through direct communication with the APC (APC 2000, 2001, 2003; SPI 2000; Eldredge-Roebuck 2000). These data were organized by year and resin type (see Table 2-41). A carbon content was assigned for each resin. These contents were based on molecular formulas and are listed in Table 2-42 and Table 2-43. In cases where the resin type is generic, referring to a group of chemicals and not a single polymer (e.g., phenolic resins, other styrenic resins), a representative compound was chosen. For engineering resins and other resins, a weighted carbon content of 65 percent was assumed (i.e., it was assumed that these resins had the same content as those for which a representative compound could be assigned).

There were no emissive uses of plastics identified, so 100 percent of the carbon was considered stored in products. However, an estimate of emissions related to the combustion of these plastics in the municipal solid waste stream can be found in the Waste Combustion section of the Energy chapter.

Table 2-41: 2002 Plastic Resin Production (Tg dry weight) and Carbon Stored (Tg CO₂ Eq.)

Resin Type	2002 Production ^a	Carbon Stored
Epoxy	0.30	0.8
Urea	0.73	0.9
Melamine	0.73	0.8
Phenolic	2.01	5.7
Low-Density Polyethylene (LDPE)	3.65	11.5
Linear Low-Density Polyethylene (LLDPE)	5.14	16.2
High Density Polyethylene (HDPE)	7.24	22.8
Polypropylene (PP)	7.69	24.2
Acrylonitrile-butadiene-styrene (ABS)	0.60	1.9
Styrene-acrylonitrile (SAN)	0.06	0.2
Other Styrenics	0.73	2.5
Polystyrene (PS)	3.03	10.2
Nylon	0.58	1.4
Polyvinyl chloride (PVC) ^b	6.94	9.8
Thermoplastic Polyester	3.29	7.5
Engineering Resins	1.24	3.0
All Other (including Polyester (unsaturated))	4.81	11.6
Total	48.76	130.8

^a Includes production from Canada for Urea, Melamine, LDPE, LLDPE, HDPE, PP, ABS, SAN, Phenolic, Other Styrenics, PS, Nylon, PVC, Thermoplastic Polyester, and Engineering Resins. Includes production from Mexico for ABS, SAN, Other Styrenics, Nylon, and Thermoplastic Polyester.

^b Includes copolymers

Note: Totals may not sum due to independent rounding.

Table 2-42: Assigned Carbon Contents of Plastic Resins (by weight)

Resin Type	Carbon Content	Source of Carbon Content Assumption
Epoxy	76%	Typical epoxy resin made from epichlorhydrin and bisphenol A
Polyester (Unsaturated)	63%	Poly (ethylene terephthalate) (PET)
Urea	34%	50% carbamal, 50% N-(hydroxymethyl) urea *
Melamine	29%	Trimethylol melamine *
Phenolic	77%	Phenol
Low-Density Polyethylene (LDPE)	86%	Polyethylene
Linear Low-Density Polyethylene (LLDPE)	86%	Polyethylene
High Density Polyethylene (HDPE)	86%	Polyethylene
Polypropylene (PP)	86%	Polypropylene
Acrylonitrile-Butadiene-Styrene (ABS)	85%	50% styrene, 25% acrylonitrile, 25% butadiene
Styrene-Acrylonitrile (SAN)	80%	50% styrene, 50% acrylonitrile
Other Styrenics	92%	Polystyrene
Polystyrene (PS)	92%	Polystyrene
Nylon	65%	Average of nylon resins (see Table 2-43)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
Engineering Resins	66%	Weighted average of other resin production
All Other	66%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table 2-43: Major Nylon Resins and their Carbon Contents (by weight)

Resin	Carbon Content
Nylon 6	64%
Nylon 6,6	64%
Nylon 4	52%
Nylon 6,10	68%
Nylon 6,11	69%
Nylon 6,12	70%
Nylon 11	72%

Synthetic Rubber

Data on synthetic rubber in scrap tires were derived from data on the scrap tire market and the composition of scrap tires from the Rubber Manufacturers' Association's (RMA) Scrap Tire Management Council (STMC). The market information is presented in the report *U.S. Scrap Tire Markets 2001* (RMA 2002), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (STMC 2003). No data were available for 2002, so 2002 tire consumption was assumed to equal 2001 consumption.

A carbon content for synthetic rubber (90%) was assigned based on the weighted average of carbon contents (based on molecular formula) by elastomer type consumed in 1998 (see Table 2-44). The 1998 consumption data were obtained from the International Institute of Synthetic Rubber Producers (IISRP) press release "Synthetic Rubber Use Growth to Continue Through 2004, Says IISRP and RMA" (IISRP 2000).

There were no emissive uses of rubber identified, so 100 percent of the carbon was assumed stored. However, emissions related to the combustion of rubber in scrap tires and consumer goods can be found in the Waste Combustion section of the Energy chapter.

Table 2-44: 1998 Rubber Consumption and Carbon Content

Elastomer Type	1998 Consumption (Thousand Metric Tons)*	Carbon Content
SBR Solid	908	91%
Polybutadiene	561	89%
Ethylene Propylene	320	86%
Polychloroprene	69	59%
NBR Solid	87	77%
Polyisoprene	78	88%
Others	369	88%
Weighted Average	-	90%
Total	2,392	-

* Includes consumption in Canada.

- Not applicable

Note: Totals may not sum due to independent rounding.

Synthetic Fibers

Annual synthetic fiber production data were obtained from the Fiber Economics Bureau, as published in *Chemical & Engineering News* (2001). These data are organized by year and fiber type. For each fiber, a carbon content was assigned based on molecular formula (see Table 2-45). For polyester, the carbon content for poly(ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average carbon content of nylon 6 and nylon 6,6 was used, since these are the most widely produced nylon fibers. Cellulosic fibers, such as acetate and rayon, have been omitted from the synthetic fibers' carbon accounting because much of their carbon is of biogenic origin. These fibers account for only 4 percent of overall fiber production by weight.

There were no emissive uses of fibers identified, so 100 percent of the carbon was considered stored. Note that emissions related to the combustion of textiles in municipal solid waste is accounted for under the Waste Combustion section of the Energy chapter.

Table 2-45: 2002* Fiber Production, Carbon Content, and Carbon Stored

Fiber Type	Production (Tg)	Carbon Content	Carbon Stored (Tg CO ₂ Eq.)
Polyester	1.8	63%	4.0
Nylon	1.2	64%	2.8
Olefin	1.4	86%	4.5
Acrylic	0.2	68%	0.4
Total	4.5	-	11.7

* 2002 production data were not available yet, so these values are set equal to 2000 production

- Not applicable

Note: Totals may not sum due to independent rounding

Carbon Black

Carbon black is a finely divided solid form of carbon produced from the partial oxidation of heavy oil fractions.⁸ It is used primarily in manufacture of tire treads and other abrasion resistant rubber products, but can also be used in pigments for paints and inks. Production data for carbon black were obtained from members of the International Carbon Black Association (Johnson 2003). In 2002, carbon black ranked 51st in chemical production in the United States with 1,682,278 metric tons produced (ACC 2003, Johnson 2003). Since carbon black is essentially pure carbon, its carbon content is 100 percent (Miller 1999). Also, since it is used in solid products and resists degradation, it was considered 100 percent stored. However, an estimate of CH₄ emissions associated with petrochemical production of carbon black can be found in the Industrial Processes chapter. For 2002, carbon stored as a result of carbon black production was estimated to be 6.2 Tg CO₂ Eq.

Pesticides

Pesticide consumption data were obtained from the *1994/1995, 1996/1997, and 1998/1999 Pesticides Industry Sales and Usage Market Estimates* (EPA 1998, 1999, 2002b) reports. The most recent data available were for 1999, so it was assumed that 2002 consumption was equal to that of 1999. Active ingredient compound names and consumption weights were available for the top 25 agriculturally-used pesticides and top 10 pesticides used in the home and garden and the industry/commercial/government categories. The report provides a range of consumption for each active ingredient; the midpoint was used to represent actual consumption. Each of these compounds was assigned a carbon content value based on molecular formula. If the compound contained aromatic rings substituted with chlorine or other halogens, then the compound was considered persistent and the carbon in the compound was assumed to be stored. All other pesticides were assumed to release their carbon to the atmosphere. Over one-third of 1999 total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 2002b). This unspecified portion of the active ingredient consumption was treated as a single chemical and assigned a carbon content and a storage factor based on the weighted average of the known chemicals' values.

Table 2-46: Active Ingredient Consumption in Pesticides (Million lbs.) and Carbon Emitted and Stored (Tg CO₂ Eq.)

Pesticide Use*	Active Ingredient	Carbon Emitted	Carbon Stored
Agricultural Uses ^a	475.0	0.1	0.2
Non-Agricultural Uses ^b	80.5	+	+
Home & Garden	33.5	+	+
Industry/Gov't/Commercial	47.0	+	+
Other	356.5	0.1	0.1
Total	912.0	0.2	0.3

+ Less than 0.05 Tg CO₂ Eq.

^a1999 estimates (EPA 2002).

Note: Totals may not sum due to independent rounding.

Soaps, Shampoos, and Detergents

Cleansers—soaps, shampoos, and detergents—are among the major consumer products that may contain fossil carbon. All of the carbon in cleansers was assumed to be fossil-derived, and, as cleansers eventually biodegrade, all of the carbon was assumed to be emitted. The first step in estimating carbon flows was to characterize the “ingredients” in a sample of cleansers. For this analysis, cleansers were limited to the following personal household cleaning products: bar soap, shampoo, laundry detergent (liquid and granular), dishwasher detergent, and dishwashing liquid. Data on the annual consumption of household personal cleansers were obtained from the U.S. Census Bureau 1997 Economic Census. Due to resource constraints, and the small mass of carbon in this category, the year 1997 was taken to be representative of the entire time series.

Chemical formulae were used to determine carbon contents (as percentages) of the ingredients in the cleansers. Each product's overall carbon content was then derived from the composition and contents of its ingredients. From these values the mean carbon content for cleansers was calculated to be 21.9 percent.

⁸ Carbon black can also be produced from the cracking of natural gas, but this method is uncommon.

The Census Bureau presents consumption data in terms of quantity (in units of million gallons or million pounds) and/or terms of value (thousands of dollars) for eight specific categories, such as “household liquid laundry detergents, heavy duty” and “household dry alkaline automatic dishwashing detergents.” Additionally, the report provides dollar values for the total consumption of “soaps, detergents, etc.—dry” and “soaps, detergents, etc.—liquid.” The categories for which both quantity and value data are available is a subset of total production. Those categories that presented both quantity and value data were used to derive pounds per dollar and gallons per dollar conversion rates, and they were extrapolated (based on the Census Bureau estimate of total value) to estimate the total quantity of dry and liquid⁹ cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined). Multiplying the mean carbon content (21.9 percent) by this value yielded an estimate of 4.9 Tg CO₂ Eq. in cleansers.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the feedstocks carbon storage factor and the quantity of carbon stored in feedstocks in 2002. Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for production data (the majority of the variables) were assumed to exhibit a normal distribution with a moderate variance of ± 20 percent; a narrow uniform distribution was applied to total carbon consumption to be consistent with the fossil fuel energy consumption uncertainty calculations. The largest uncertainty surrounded the activity data estimate of net exports of petrochemical feedstocks— ± 50 percent.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 67.4 percent, with a standard deviation of 1 percent and 95 percent confidence limits of 66 percent and 69 percent. This compares to the calculated estimate, used in the inventory, of 67.4 percent. The analysis produced a carbon storage distribution approximating a normal curve with a mean of 38.71 Tg C, standard deviation of 0.98 Tg C, and 95% confidence limits of 36.9 and 40.6 Tg C. This compares with a calculated estimate of 38.1 Tg C. The apparently tight confidence limits for the storage factor and carbon storage probably understate uncertainty, as a result of the way this initial analysis was structured. As discussed above, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and nine that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all 15 of these fate processes, the current analysis addresses only the storage fates, and assumes that all carbon that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As far as specific sources of uncertainty, there are several cross-cutting factors that pervade the characterization of carbon flows for feedstocks. The aggregate storage factor for petrochemical feedstocks, pentanes plus, liquefied petroleum gases, and natural gas is based on assuming that the ultimate fates of all of these fuel types—in terms of storage and emissions—are similar. In addition, there are uncertainties associated with the simplifying assumptions made for each end use category carbon estimate. Generally, the estimate for a product is subject to one or both of the following uncertainties:

- The value used for estimating the carbon content has been assumed or assigned based upon a representative compound.
- The split between carbon storage and emission has been assumed based on an examination of the environmental fate of the products in each end use category.
- Environmental fates leading to emissions are assumed to operate rapidly, i.e., emissions are assumed to occur within one year of when the fossil carbon enters the non-energy mass balance. Some of the pathways that lead to emissions as CO₂ may take actually place on a time-scale of several years or decades. By attributing the emissions to the year in which the carbon enters the mass balance (i.e., the year in which it

⁹ A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

leaves refineries as a non-energy fuel use and thus starts being tracked by EIA), this approach has the effect of “front-end loading” the emission profile.

Another cross-cutting source of uncertainty is that for several sources the amount of carbon stored or emitted was calculated based on data for only a single year. This specific year may not be representative of storage for the entire inventory period. Sources of uncertainty associated with specific elements of the analysis are discussed below.

Import and export data for petrochemical feedstocks were obtained from EIA, the National Petroleum Refiners Association, and the U.S. BoC for the major categories of petrochemical feedstocks (EIA 2001a, NPRA 2001, U.S. BoC 2003). The list of commodities for which imports and exports were analyzed is not comprehensive in tracking fossil fuel-derived feedstocks and may underestimate net exports of carbon.

Oxidation factors have been applied to non-energy uses of petrochemical feedstocks in the same manner as for energy uses. However, this “oxidation factor” may be inherent in the storage factor applied when calculating emissions from non-energy consumption, which would result in a double-counting of the unoxidized carbon. Oxidation factors are small corrections, on the order of 1 percent, and therefore application of oxidation factors to non-energy uses may result in a slight underestimation of carbon emissions from non-energy uses.

The major uncertainty in using the TRI data are the possibility of double counting of emissions that are already accounted for in the NMVOC data (see above) and in the storage and emission assumptions used. The approach for predicting environmental fate simplifies some complex processes, and the balance between storage and emissions is very sensitive to the assumptions on fate. Extrapolating from known to unknown characteristics also introduces uncertainty. The two extrapolations with the greatest uncertainty are: 1) that the release media and fate of the off-site releases were assumed to be the same as for on-site releases, and 2) that the carbon content of the least frequent 10 percent of TRI releases was assumed to be the same as for the chemicals comprising 90 percent of the releases. However, the contribution of these chemicals to the overall estimate is small. The off-site releases only account for 3 percent of the total releases, by weight, and, by definition, the less frequent compounds only account for 10 percent of the total releases.

The principal sources of uncertainty in estimating CO₂ emissions from solvent evaporation and industry are in the estimates of total NMVOC emissions and in the application of factors for the carbon content of these emissions. Solvent evaporation and industrial NMVOC emissions reported by EPA are based on a number of data sources and emission factors, and may underestimate or overestimate emissions. The carbon content for solvent evaporation emissions is calculated directly from the specific solvent compounds identified by EPA as being emitted, and is thought to have relatively low uncertainty. The carbon content for industrial emissions has more uncertainty, however, as it is calculated from the average carbon content of an average volatile organic compound based on the list of the most abundant measured NMVOCs provided in EPA (2002a).

Uncertainty in the hazardous waste combustion analysis is introduced by the assumptions about the composition of combusted hazardous wastes, including the characterization that hazardous wastes are similar to mixtures of water, noncombustibles, and fuel equivalent materials. Another limitation is the assumption that all of the carbon that enters hazardous waste combustion is emitted—some small fraction is likely to be sequestered in combustion ash—but given that the destruction and removal efficiency for hazardous organics is required to meet or exceed 99.99 percent, this is a very minor source of uncertainty. Carbon emission estimates from hazardous waste should be considered central value estimates that are likely to be accurate to within ± 50 percent.

The amount of feedstocks combusted for energy recovery was estimated from data included in the Manufacturers Energy Consumption Surveys (MECS) for 1991, 1994, and 1998 (EIA 1994, 1997, 2001b). MECS is a comprehensive survey that is conducted every four years and intended to represent U.S. industry as a whole, but because EIA does not receive data from all manufacturers (i.e., it is a sample rather than a census), EIA must extrapolate from the sample. Also, the “other” fuels are identified in the MECS data in broad categories, including refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; and other uncharacterized fuels. Moreover, the industries using these “other” fuels are also identified only in broad categories, including the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. The “other” fuel consumption data are reported in BTUs (energy units) and there is uncertainty concerning the selection of a specific conversion factor for each broad “other” fuel category to convert energy units to mass units. Taken as a whole, the estimate of energy recovery emissions probably introduces more uncertainty than any other element of the non-energy analysis.

Uncertainty in the carbon storage estimate for plastics arises primarily from three factors. First, the production data for several resins include Canadian and/or Mexican production and may overestimate the amount of plastic produced from U.S. fuel feedstocks. Second, the assumed carbon content values are estimates for representative compounds, and thus do not account for the many formulations of resins available. This uncertainty is greater for resin categories that are generic (e.g., phenolics, other styrenics, nylon) than for resins with more specific formulations (e.g., polypropylene, polyethylene). Lastly, the assumption that all of the carbon contained in plastics is stored ignores certain end uses (e.g., adhesives and coatings) where the resin may be released to the atmosphere; however, these end uses are likely to be small relative to use in plastics.

The quantity of carbon stored in synthetic rubber only accounts for the carbon stored in scrap tire synthetic rubber. The value does not take into account the rubber stored in other durable goods, clothing, footwear, and other non-durable goods, or containers and packaging. This adds uncertainty to the total mass balance of carbon stored. There are also uncertainties as to the assignment of carbon content values; however, they are much smaller than in the case of plastics. There are probably fewer variations in rubber formulations than in plastics, and the range of potential carbon content values is much narrower. Lastly, assuming that all of the carbon contained in rubber is stored ignores the possibility of volatilization or degradation during product lifetimes. However, the proportion of the total carbon that is released to the atmosphere during use is probably negligible.

A small degree of uncertainty arises from the assignment of carbon content values; however, the magnitude of this uncertainty is less than that for plastics or rubber. Although there is considerable variation in final textile products, the stock fiber formulations are standardized and proscribed explicitly by the Federal Trade Commission.

For pesticides, the largest source of uncertainty involves the assumption that an active ingredient's carbon is either 0 percent stored or 100 percent stored. This split is a generalization of chemical behavior, based upon active-ingredient molecular structure, and not on compound-specific environmental data. The mechanism by which a compound is bound or released from soils is very complicated and can be affected by many variables, including the type of crop, temperature, delivery method, and harvesting practice. Another smaller source of uncertainty arises from the carbon content values applied to the unaccounted for portion of active ingredient. Carbon contents vary widely among pesticides, from 7 to 72 percent, and the remaining pesticides may have a chemical make-up that is very different from the 32 pesticides that have been examined. Additionally, pesticide consumption data were only available for 1987, 1993, 1995, 1997, and 1999; the majority of the time series data were interpolated or held constant at the latest (1999) value.

It is important to note that development of this uncertainty analysis is a multi-year process. The current analysis only examines NEU fuels that end in storage fates, not those that are emitted. Thus only carbon stored in carbon black, pesticides, plastics, synthetic fibers, synthetic rubbers, and TRI releases to underground injection and Subtitle C landfills is accounted for in the estimates above. In the next two years this analysis will be expanded to include the uncertainty surrounding emitted fates in addition to the storage fates. Estimates of variable uncertainty will also be refined where possible to include fewer assumptions. With these major changes in future Inventories, the uncertainty estimate is expected to change, and likely increase. An increase in the uncertainty estimate in the coming years will not indicate that the Inventory calculations have become less certain, but rather that the methods for estimating uncertainty have become more comprehensive; thus, potential future changes in the results of this analysis will reflect a change in the uncertainty analysis, not a change in the Inventory quality.

Asphalt and Road Oil

Asphalt is one of the principal non-energy uses of fossil fuels. The term "asphalt" generally refers to a mixture of asphalt cement and a rock material aggregate, a volatile petroleum distillate, or water. For the purposes of this analysis, "asphalt" is used interchangeably with asphalt cement, a residue of crude oil. According to EPA (2000d), approximately 100 Tg CO₂ Eq. has been used in the production of asphalt cement annually. Though minor amounts of carbon are emitted during production, asphalt has an overall carbon storage factor of almost 100 percent, as discussed below.

Paving is the primary application of asphalt cement, comprising 86 percent of production. The three types of asphalt paving produced in the United States are hot mix asphalt (HMA), cut-backs, and emulsified asphalt. HMA, which makes up 90 percent of total asphalt paving (EPA 2000c), contains asphalt cement mixed with an aggregate of rock materials. Cut-back asphalt is composed of asphalt cement thinned with a volatile petroleum distillate (e.g., naphtha). Emulsified asphalt contains only asphalt cement and water. Roofing products are the other significant end use of asphalt cement, accounting for approximately 14 percent of U.S. production (Kelly 2000). No

data were available on the fate of carbon in asphalt roofing; it was assumed that it has the same fate as carbon in asphalt paving applications.

Methodology and Data Sources

A carbon storage factor was calculated for each type of asphalt paving. The fraction of carbon emitted by each asphalt type was multiplied by consumption data for asphalt paving (EPA 2000c, EIIP 1998) to come up with a weighted average carbon storage factor for asphalt as a whole.

The fraction of carbon emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide, polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2000c) and total HMA production.¹⁰ The next step was to estimate the carbon content of the organic emissions. This calculation was based on the carbon content of carbon monoxide (CO) and phenol, and an assumption of 85 percent carbon content for PAHs and HAPs. The carbon content of asphalt paving is a function of the proportion of asphalt cement in asphalt paving and the proportion of carbon in asphalt cement. For the former factor, a 5 percent asphalt cement content was assumed based on personal communication with an expert from the National Asphalt Paving Association (Connolly 2000). For the latter factor, all paving types were characterized as having a mass fraction of 85 percent carbon in asphalt cement, based on the assumption that asphalt is primarily composed of saturated paraffinic hydrocarbons. By combining these estimates, the result is that over 99.99 percent of the carbon in asphalt cement was retained (i.e., stored), and less than 0.01 percent was emitted.

Cut-back asphalt is produced in three forms (i.e., rapid, medium and slow cure). All three forms emit carbon only from the volatile petroleum distillate used to thin the asphalt cement (EPA 1995). Because the petroleum distillates are not included in the EIA fuel use statistics for asphalt, the storage factor for cut-back is assumed to be 100 percent.

It was also assumed that there was no loss of carbon from emulsified asphalt (i.e., the storage factor is 100 percent) based on personal communication with an expert from Akzo Nobel Coatings, Inc. (James 2000).

Data on asphalt and road oil consumption and carbon content factors were supplied by EIA. Hot mix asphalt production and emissions factors were obtained from “Hot Mix Asphalt Plants Emissions Assessment Report” from EPA’s *AP-42* (EPA 2000c) publication. The asphalt cement content of HMA was provided by Una Connolly of National Asphalt Paving Association (Connolly 2000). The consumption data for cut-back and emulsified asphalts were taken from a Moulthrop, et al. study used as guidance for estimating air pollutant emissions from paving processes (EIIP 1998). “Asphalt Paving Operation” *AP-42* (EPA 1995) provided the emissions source information used in the calculation of the carbon storage factor for cut-back asphalt. The storage factor for emulsified asphalt was provided by Alan James of Akzo Nobel Coatings, Inc. (James 2000).

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the asphalt carbon storage factor and the quantity of carbon stored in asphalt in 2002. Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for asphalt production were assumed to be rather high (± 50 percent), while the asphalt property variables were assumed to have narrower distributions. Narrow uniform distributions were applied to total consumption of asphalt and road oil and the carbon content coefficients to be consistent with the fossil fuel energy consumption uncertainty calculations.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve skewed to the right, around a mean of 99.0 percent, with a standard deviation of 0.5 percent and 95 percent confidence limits

¹⁰ The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

of 97.8 percent and 99.6 percent. This compares to the calculated mean of 99.6 percent, and the value used in the inventory of 100 percent. The analysis produced a carbon storage distribution that appears triangular, with a mean of 25.7 Tg C, standard deviation of 0.79 Tg C, and 95 percent confidence limits of 24.2 Tg C and 27.2 Tg C. This compares with the inventory estimate of 25.6 Tg C.

The principal source of uncertainty is that the available data are from short-term studies of emissions associated with the production and application of asphalt. As a practical matter, the cement in asphalt deteriorates over time, contributing to the need for periodic re-paving. Whether this deterioration is due to physical erosion of the cement and continued storage of carbon in a refractory form or physicochemical degradation and eventual release of CO₂ is uncertain. Long-term studies may reveal higher lifetime emissions rates associated with degradation.

Many of the values used in the analysis are also uncertain and are based on estimates and professional judgment. For example, the asphalt cement input for hot mix asphalt was based on expert advice indicating that the range is variable—from about 3 to 5 percent—with actual content based on climate and geographical factors (Connolly 2000). Over this range, the effect on the calculated carbon storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed carbon content of asphalt cement would have only a minor effect.

The consumption figures for cut-back and emulsified asphalts are based on information reported for 1994. More recent trends indicate a decrease in cut-back use due to high VOC emission levels and a related increase in emulsified asphalt use as a substitute. However, because the carbon storage factor of each is 100 percent, use of more recent data would not affect the overall result.

Future improvements to this uncertainty analysis, and to the overall estimation of a storage factor for asphalt, include characterizing the long-term fate of asphalt.

Lubricants

Lubricants are used in industrial and transportation applications. They can be subdivided into oils and greases, which differ in terms of physical characteristics (e.g., viscosity), commercial applications, and environmental fate. According to EIA (2003), the carbon content of U.S. production of lubricants in 2002 was approximately 6.8 Tg C. Based on apportioning oils and greases to various environmental fates, and characterizing those fates as resulting in either long-term storage or emissions, the overall carbon storage factor was estimated to be 9 percent; thus, storage in 2002 was about 0.6 Tg C, or 2.3 Tg CO₂ Eq.

Methodology and Data Sources

For each lubricant category, a storage factor was derived by identifying disposal fates and applying assumptions as to the disposition of the carbon for each practice. An overall lubricant carbon storage factor was calculated by taking a production-weighted average of the oil and grease storage factors.

Oils

Regulation of used oil in the United States has changed dramatically over the past 15 years.¹¹ The effect of these regulations and policies has been to restrict landfilling and dumping, and to encourage collection of used oil. Given the relatively inexpensive price of crude oil, the economics have not favored re-refining—instead, most of the used oil that has been collected has been combusted.

Table 2-47 provides an estimated allocation of the fates of lubricant oils (Rinehart 2000), along with an estimate of the proportion of carbon stored in each fate. The ultimate fate of the majority of oils (about 84 percent) is combustion, either during initial use or after collection as used oil. Combustion results in 99 percent oxidation to CO₂ (EIIP 1999), with correspondingly little long-term storage of carbon in the form of ash. Dumping onto the ground or into storm sewers, primarily by “do-it-yourselfers” who change their own oil, is another fate that results in conversion to CO₂ given that the releases are generally small and most of the oil is biodegraded (based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading

¹¹ For example, the U.S. EPA “RCRA (Resource Conservation and Recovery Act) On-line” web site (<<http://www.epa.gov/rcraonline/>>) has over 50 entries on used oil regulation and policy for 1994 through 2000.

refinery wastes). In the landfill environment, which tends to be anaerobic within municipal landfills, it is assumed that 90 percent of the oil persists in an undegraded form, based on analogy with the persistence of petroleum in native petroleum-bearing strata, which are both anaerobic. Re-refining adds a recycling loop to the fate of oil. Re-refined oil was assumed to have a storage factor equal to the weighted average for the other fates (i.e., after re-refining, the oil would have the same probability of combustion, landfilling, or dumping as virgin oil), i.e., it was assumed that about 97 percent of the carbon in re-refined oil is ultimately oxidized. Because of the dominance of fates that result in eventual release as CO₂, only about 3 percent of the carbon in oil lubricants goes into long-term storage.

Table 2-47: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total Oil	Carbon Stored
Combusted During Use	20	1
Not Combusted During Use	80	-
Combusted as Used Oil*	64	1
Dumped on the ground or in storm sewers	6	0
Landfilled	2	90
Re-refined into lube oil base stock and other products	8	3
Weighted Average	-	2.9

* (e.g., in boilers or space heaters)

- Not applicable

Greases

Table 2-48 provides analogous estimates for lubricant greases. Unlike oils, grease is generally not combusted during use, and combustion for energy recovery and re-refining are thought to be negligible. Although little is known about the fate of waste grease, it was assumed that 90 percent of the non-combusted portion is landfilled, and the remainder is dumped onto the ground or storm sewers. Because much of the waste grease will be in containers that render it relatively inaccessible to biodegradation, and because greases contain longer chain paraffins, which are more persistent than oils, it was assumed that 90 percent and 50 percent of the carbon in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

Table 2-48: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Total Grease	Carbon Stored
Combusted During Use	5	1
Not Combusted During Use	95	-
Landfilled	85.5	90
Dumped on the ground or in storm sewers	9.5	50
Weighted Average	-	81.8

- Not applicable

Having derived separate storage factors for oil and grease, the last step was to estimate the weighted average for lubricants as a whole. No data were found apportioning the mass of lubricants into these two categories, but the U.S. Census Bureau (1999) does maintain records of the value of production of lubricating oils and lubricating greases. Assuming that the mass of lubricants can be allocated according to the proportion of value of production (92 percent oil, 8 percent grease), applying these weights to the storage factors for oils and greases (3 percent and 82 percent) yields an overall storage factor of 9 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the lubricants weighted average carbon storage factor and the quantity of carbon stored in lubricants in 2002. Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for oil and grease variables were assumed to have a moderate variance, in triangular or

uniform distribution; narrow uniform distributions were applied to total consumption of lubricants and the carbon content coefficients to be consistent with the fossil fuel energy consumption uncertainty calculations.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 10.5 percent, with a standard deviation of 2.8 percent and 95 percent confidence limits of 5.5 percent and 16.5 percent. This compares to the calculated estimate, used in the inventory, of 9.2 percent. The analysis produced a carbon storage distribution approximating a normal curve with a mean of 0.73 Tg C, standard deviation of 0.20 Tg C, and 95 percent confidence limits of 0.38 and 1.1 Tg C. This compares with a calculated estimate of 0.63 Tg C.

The principal sources of uncertainty for the disposition of lubricants are the estimates of the commercial use, post-use, and environmental fate of lubricants, which, as noted above, are largely based on assumptions and judgment. There is no comprehensive system to track used oil and greases, which makes it difficult to develop a verifiable estimate of the commercial fates of oil and grease. The environmental fate estimates for percent of carbon stored are less uncertain, but also introduce uncertainty in the estimate.

The assumption that the mass of oil and grease can be divided according to their value also introduces uncertainty. Given the large difference between the storage factors for oil and grease, changes in their share of total lubricant production have a large effect on the weighted storage factor.

Future improvements to the analysis of uncertainty surrounding the lubricants carbon storage factor and carbon stored include further refinement of the uncertainty estimates for the individual activity variables.

Other Non-Energy Uses

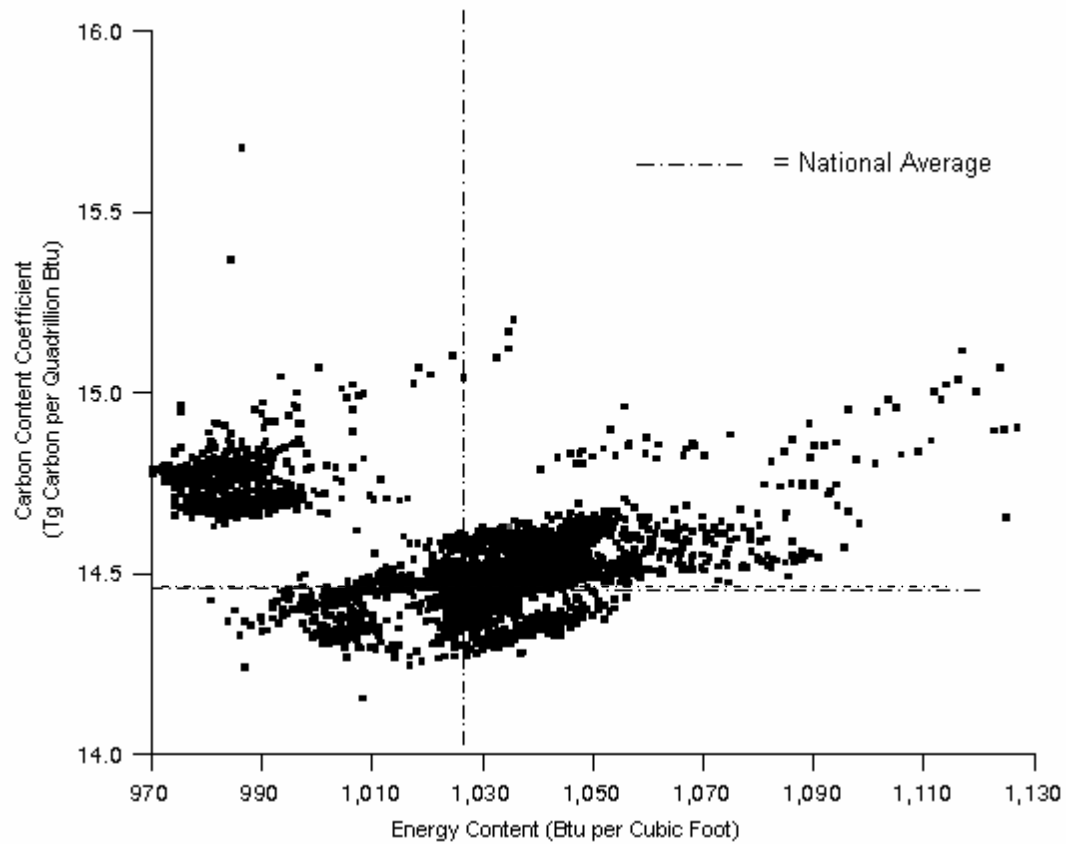
For the remaining fuel types (i.e., industrial coking coal, still gas, petroleum coke, special naphtha, distillate fuel oil, residual fuel oil, waxes, and miscellaneous products), carbon storage factors were obtained from IPCC (1997), which cites Marland and Rotty (1984) as the original source. The overall methodology simply involves multiplying carbon content by a storage factor, yielding an estimate of the mass of carbon stored. To provide a complete analysis of uncertainty for the entire NEU subcategory, the uncertainty around the estimate of “other” NEUs was characterized, as discussed below.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the average of the remaining fuels’ carbon storage factors and the total quantity of carbon stored in these other fuels in 2002. Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Narrow uniform distributions were applied to fuel consumption and the carbon content coefficients to be consistent with the fossil fuel energy consumption uncertainty calculations; the fuel-specific storage factors were assigned wide triangular distributions indicating greater uncertainty.

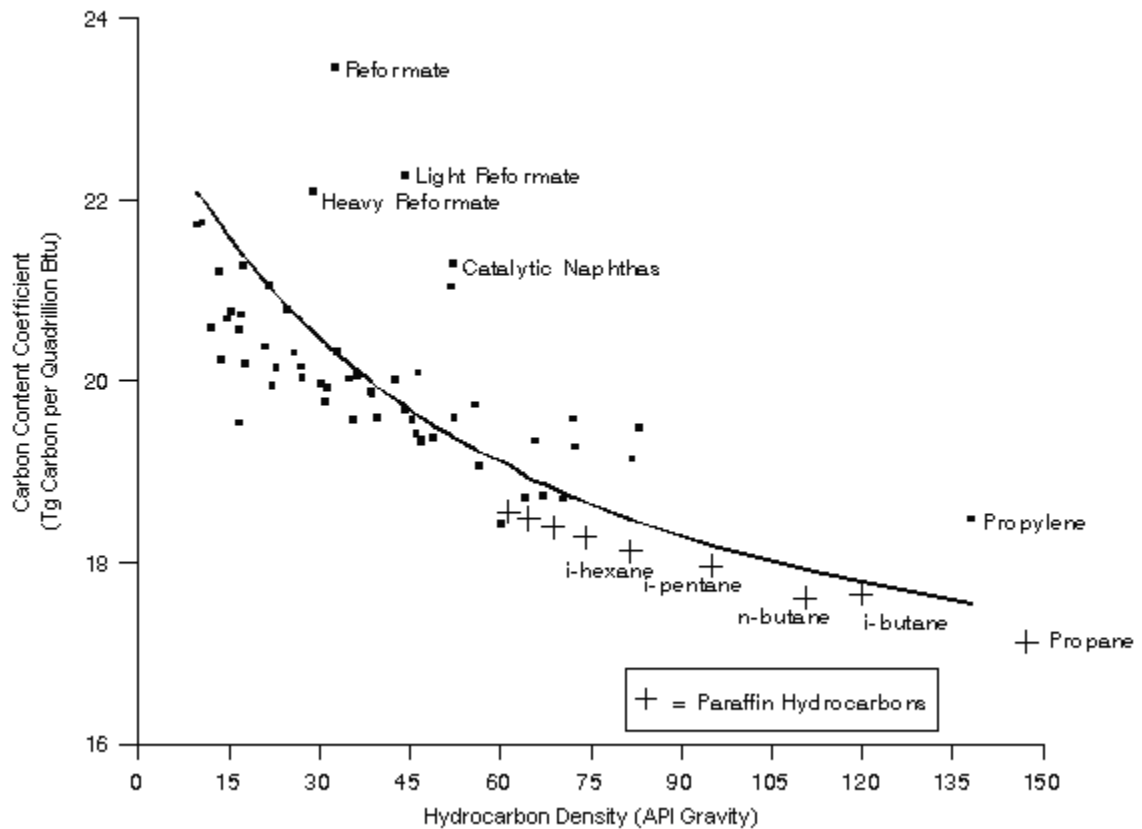
The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 49 percent, with a standard deviation of 10 percent and 95 percent confidence limits of 31 percent and 68 percent. This compares to the calculated, weighted average (across the various fuels) value of 48 percent. The analysis produced a carbon storage distribution approximating a normal curve with a mean of 7.3 Tg C, standard deviation of 1.4 Tg C, and 95 percent confidence limits of 4.54 Tg C and 10.07 Tg C. This compares with the inventory estimate of 6.9 Tg C.

Figure 2-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database



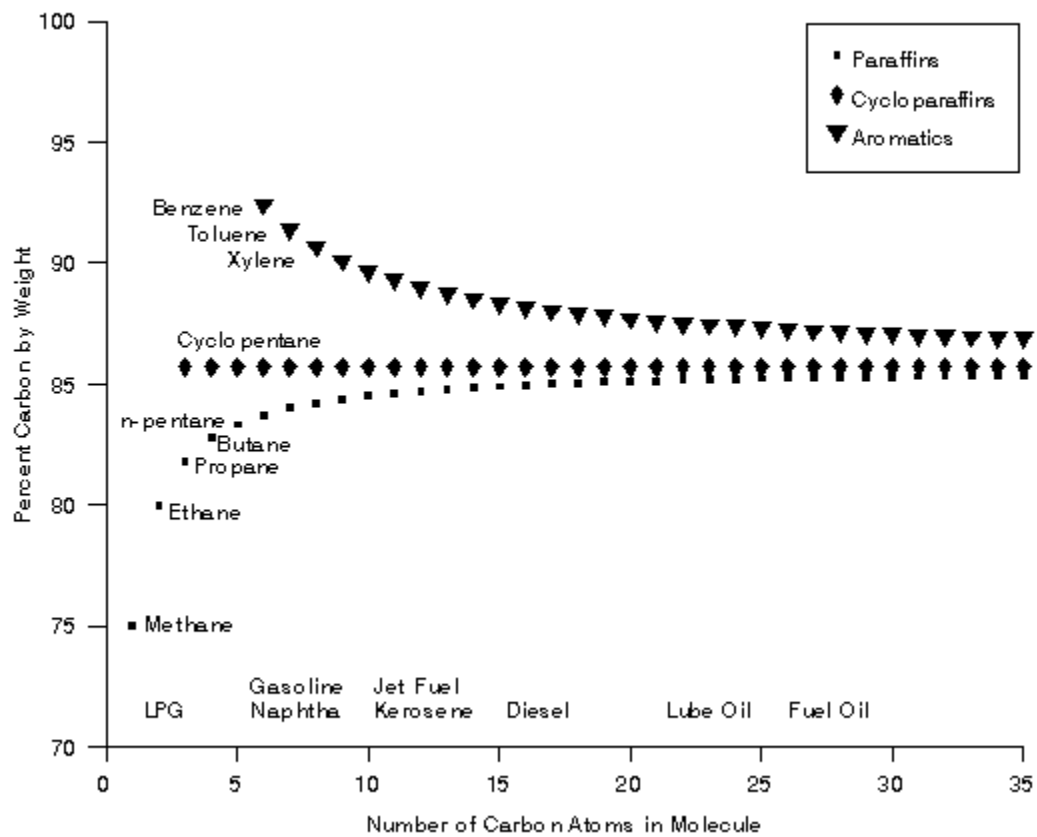
Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Figure 2-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density



Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in V. Guthrie (ed.), *Petroleum Products Handbook* (New York: McGraw Hill, 1960) p. 33. Carbon content factors from other petroleum products are drawn from sources described below. Relationship between density and emission factors based on the relationship between density and energy content in U.S. Department of Commerce, National Bureau of Standards, *Thermal Properties of Petroleum Products*, Miscellaneous Publication, No. 97 (Washington, D.C., 1929), pp.16-21, and relationship between energy content and fuel composition in S. Ringen, J. Lanum, and F.P. Miknis, "Calculating Heating Values from the Elemental Composition of Fossil Fuels," *Fuel*, Vol. 58 (January 1979), p.69.

Figure 2-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number



Source: J.M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco, CA, W.H. Freeman and Company, 1979), pp. 31-37.

Descriptions of Figures: Annex 2

Figure 2-1 shows the relationship between the calculated carbon contents for each natural gas sample and its energy content. This figure illustrates the relatively restricted range of variation in both the energy content (which varies by about 6 percent from average) and the carbon emission coefficient of natural gas (which varies by about 5 percent). Thus, the knowledge that gas has been sold via pipeline to an end-use consumer allows its carbon emission coefficient to be predicted with an accuracy of ± 5.0 percent.

Figure 2-2 compares carbon content coefficients calculated on the basis of the derived formula with actual carbon content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The estimated relationship is shown as a line depicting decreasing carbon content with increasing hydrocarbon density. The actual relationship is appears as dozens of points scattered along this line.

Figure 2-3 illustrates the share of carbon by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules are generally used as lubricants, waxes, and residual fuel oil.